



**FEUP** FACULDADE DE ENGENHARIA  
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# Comparing centralized vs decentralized hydrogen hubs development

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***Master Dissertation***

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## Abstract

This dissertation addresses the study of the introduction of hydrogen produced via electrolysis in the energy supply of industrial processes in Amcor flexibles PT in Porto and is divided in two main scenarios: the installation of a small-scale decentralized hydrogen production unit for self-consumption and a larger scale, centralized, hydrogen production infrastructure.

The first scenario in question aims to assess the potential of the installation of a local, decentralized hydrogen production unit via electrolysis in Amcor's facilities, with the objective of blending relatively low percentages of hydrogen in their gas grid, to meet their energy needs and reduce the dependence on natural gas. The second scenario under study consists in having a centralized hydrogen production, at a given location, where hydrogen is produced in larger scale and afterwards, the amount needed to supply Amcor's demand is transported from the place of production to their facilities.

These two situations will be analyzed, and the costs associated with each one will be assessed to understand how feasible each of the situations is.

**Keywords:** Decarbonization; Renewable energy; Hydrogen; Electrolysis; Blending

## Resumo

A presente dissertação incide sobre o estudo da introdução de hidrogénio, produzido por eletrólise, no abastecimento energético dos processos industriais da Amcor Flexibles PT, no Porto. Este estudo é dividido em dois cenários principais: a instalação de uma unidade de produção de hidrogénio descentralizada, em pequena escala, para autoconsumo e, por outro lado, a construção de uma infraestrutura de produção de hidrogénio centralizada, em grande escala.

O primeiro cenário abordado visa avaliar o potencial da instalação de uma unidade local, descentralizada, de produção de hidrogénio, nas instalações da Amcor, com o objetivo de injetar percentagens relativamente baixas de hidrogénio na rede de gás desta indústria, para satisfazer as suas necessidades energéticas e reduzir a dependência do gás natural. No que diz respeito ao segundo cenário, o estudo consistiu em avaliar uma produção centralizada de hidrogénio, num determinado local, onde a produção é em muito maior escala e, posteriormente, o hidrogénio necessário para satisfazer as necessidades da Amcor e transportado até às suas instalações.

Estas duas situações serão analisadas, e os custos associados a cada uma delas serão avaliados para compreender a viabilidade de cada um dos cenários.

**Palavras-chave:** Descarbonização; Energias renováveis; Hidrogénio; Eletrólise; Blending

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## List of abbreviations

|                 |                                        |
|-----------------|----------------------------------------|
| ALK             | Alkaline electrolyzers                 |
| AEM             | Anion exchange membrane electrolyser   |
| CAPEX           | Capital expenditure                    |
| CCS             | Carbon capture and storage             |
| CCUS            | Carbon capture utilization and storage |
| CO <sub>2</sub> | Carbon dioxide                         |
| DRI             | Direct reduction of iron               |
| EZ              | Electrolyser                           |
| FCEVs           | Fuel cell electric vehicles            |
| GHG             | Greenhouse gases                       |
| H <sub>2</sub>  | Hydrogen                               |
| HHV             | Higher heating value                   |
| LH <sub>2</sub> | Liquified hydrogen                     |
| LOHC            | Liquid organic hydrogen carriers       |
| NG              | Natural gas                            |
| NH <sub>3</sub> | Ammonia                                |
| NZE             | Net Zero Scenario                      |
| O&M             | Operations and maintenance             |
| OPEX            | Operational expenditure                |
| PEM             | Proton exchange membrane electrolyzers |
| RoW             | Rest of world                          |
| SOEC            | Solid oxide electrolyzers              |
| t/d             | Tones per day                          |



# 1. Introduction

## 1.1 Context and relevance of the topic

Nowadays, the urgent need to decarbonize has led many governments and companies to adopt strategies and define targets to achieve carbon neutrality. This process of decarbonization consists in reducing greenhouse gases (GHG) emissions resulting from human activity, with eventual goal balancing the emissions and the planet's capture capacity which can be achieved by switching to usage of low carbon energy sources.

The decarbonization process, will play a fundamental role in the path to fulfil the ambitious climate goals, which focus on limiting global warming and hold the rise in average global temperatures at 1.5°C [1].

One of the measures to implement is electrification, powered by renewable energies, of several end-use processes, which would result in the substitution of a large quantity of fossil fuels based energy by clean sources of energy [2]. However, there are some sectors which are difficult to decarbonize only by direct electrification such as steel, chemicals, long-haul transport, shipping and aviation [1].

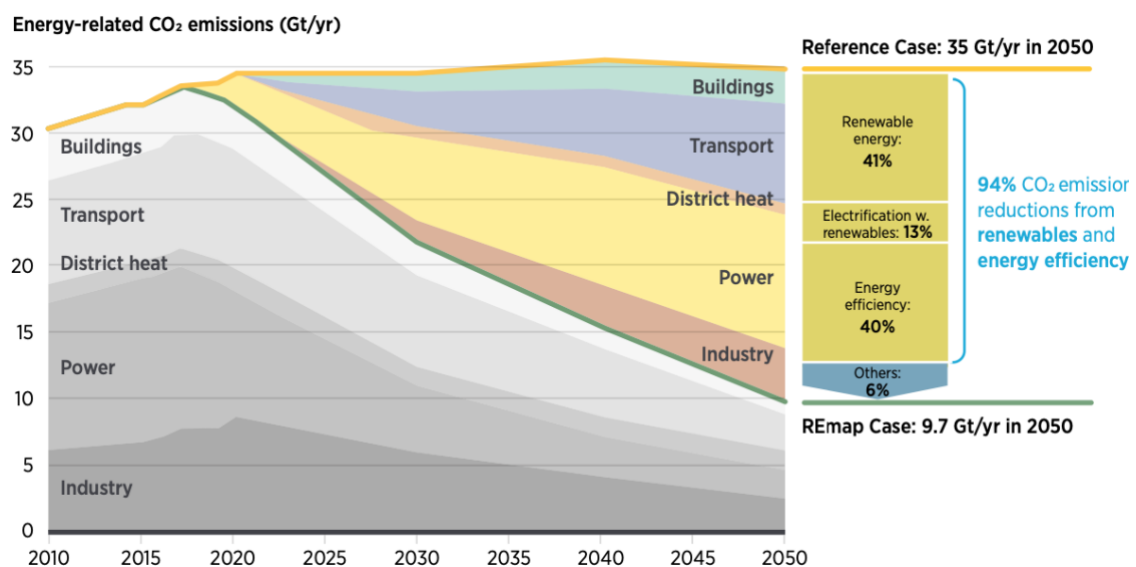


Figure 1: Carbon dioxide (CO<sub>2</sub>) emission reductions needed by 2050, compared to 2017 [3].

The emissions from these energy-intensive industries have increased steadily with the growing global demand for materials, driven in turn by increased global wealth and urban populations, and associated infrastructure development [4]. As can be seen in Figure 1, there is still a long way to go and a large amount of CO<sub>2</sub> emissions to reduce in many sectors, in order to achieve the decarbonizing goals set for 2050.

In fact, today's challenge to decarbonize and shift from fossil fuel energy sources to renewable and clean ones leaves us before an evident energy transition. There are some options that have been talked about to go along with this process and help achieve the goals set, with hydrogen being one of the main ones.

This way, the struggles that come with the decarbonization process such as the difficulties in electrifying certain sectors can be met with hydrogen or derivative products), which itself can be produced using renewable power. Hydrogen allows large amounts of renewable energy to be channeled from the power sector into different end use sectors, as shown in Figure 2. Hydrogen could therefore be the missing link in the energy transition: renewable electricity can be used to produce hydrogen, which can in turn provide energy to sectors otherwise difficult to decarbonize through electrification [2].

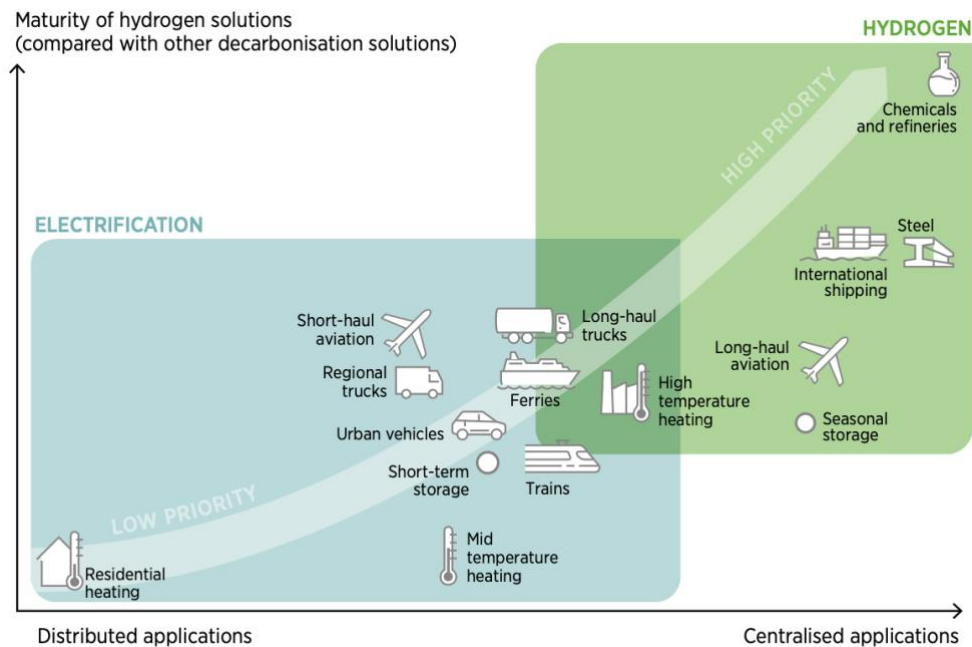


Figure 2: Green hydrogen policy priority [4].

Consequently, the gain of consciousness of the importance of hydrogen in the energy mix is empowering the power-to-hydrogen concept for many reasons:

- Hydrogen produced with excess electricity can be stored for later use in many different sectors;
- Can increase the share of renewable energy in the power sector [5];
- Allows long-term storage to manage the variation in power supply from renewable technologies [5];
- Can also enable the use of clean hydrogen, produced from renewable energy sources, as feedstock in industrial processes and thereby help decarbonize other sectors [5];
- This flexible use of hydrogen can be important in the energy transition.

The investment in hydrogen can in fact help to decarbonize several end use sectors such as:

- **Industry:** it can replace the  $H_2$  feedstock produced via fossil fuels and can also directly replace the fossil fuels used as energy source in high emission applications [2];
- **Buildings and power:** where it could be mixed with natural gas or combined with industrial carbon dioxide ( $CO_2$ ) emissions to produce syngas [2];
- **Transport:** it can provide low-carbon mobility through fuel-cell electric vehicles and can also be transformed in other fuels such as methanol, ammonia and synthetic aviation fuels [2].

Even though green hydrogen has all this potential and has everything to become a vital piece in the future energy mix, nowadays the scenario is far from this. One of the main reasons that explains this is the fact that all the costs surrounding its production make it not as economically viable as other forms of energy such as hydrogen produced via fossil fuels. As a matter of fact, green hydrogen is still 2-3 times more expensive than other types of hydrogen produced with fossil fuels [1].

In fact, the largest single cost component for on-site production of green hydrogen is the cost of the renewable electricity needed to power the electrolyser unit. A low cost of electricity is therefore a necessary condition for producing competitive green hydrogen. This creates an opportunity to produce hydrogen at locations around the world that have optimal renewable resources, in order to achieve competitiveness [1].

The second main cost component in the production of green hydrogen are the electrolysis facilities needed. While the technology is today still expensive, there are already outlined key strategies to reduce investment costs for electrolysis plants from 40% in the short term to 80% in the long term [1]. These predictions are made based on a wide range of expected improvements from the electrolyser design to broader system-wide elements such as: construction, economies of scale, procurement of materials, efficiency and flexibility in operations, industrial specific operations and learning rates with time [1].

Thus, by the combination of cheaper electricity and reduced electrolyser capex investment, in addition to increased efficiency and optimized operation of the electrolyser which may come with increased technological development, an 80% reduction in the costs of the green hydrogen production chain may be achieved, as it's shown in Figure 3 [1].

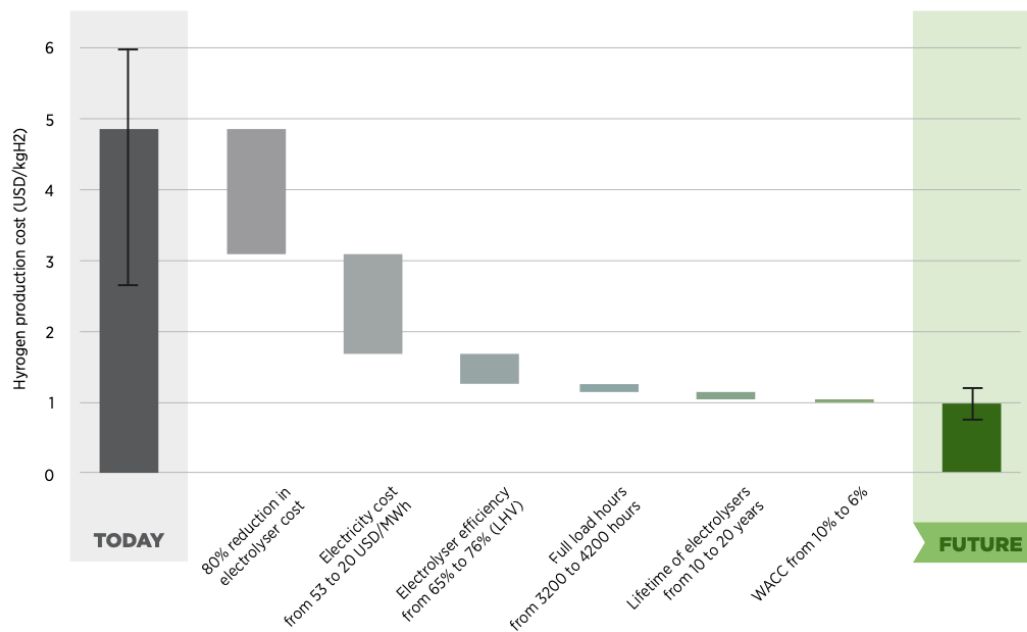


Figure 3: Cost reductions possible in green hydrogen production in the long-term [1].

## 1.2 Motivation

The urgent need for decarbonization and the consequent obligation to reduce the emissions across all sectors to reach the goals set at the Paris Agreement for 2050, highlight the need for industries to begin looking at their decarbonization options. In fact, it has already begun, and it is expected to scale up even more in the upcoming years an unavoidable, energy transition.

This pathway, which requires a massive change in how societies produce and consume energy, relies on electrification and efficiency as key drivers of the energy transition, enabled by renewables, hydrogen, sustainable biomass and others [6].

Therefore, in this new era, major investors and big companies will certainly direct large amounts of time and resources to develop these new technologies and make big investments to adapt their businesses to this new reality and carve out new strategic options for themselves.

For this reason, this is a key time to direct attentions to this emerging market, which is the hydrogen market and start paving the way to decarbonization, by promoting a hydrogen economy as an essential driver to a low carbon future.

## 1.3 Main objectives of the project

Following what was said above, the present study aims to evaluate the potential of the introduction of hydrogen in a real case study industrial environment. With that said,

with energy consumption data available from Amcor Flexible PT, an industrial facility located near Porto, the feasibility of blending hydrogen in the gas used by Amcor, up to certain percentages, to start to reduce the dependence on natural gas without affecting the good functioning of equipment and quality of the process, was tested out. To conduct the study, 4 different hydrogen blend percentages were considered, to assess the impact of the increasing amount of hydrogen to introduce.

Another objective associated with the project was to study two different approaches regarding the production of hydrogen, and the benefits from each one. First, a decentralized, local, small-scale, hydrogen production unit for self-consumption and a second approach with a centralized, large-scale hydrogen production facility, where the hydrogen demand on site was met by transporting hydrogen from the production location to the end-use point of consumption.

To sum up, for each case it was performed a technical-economic analysis with the objective of evaluating the financial viability associated with technical ability of assembling a hydrogen production unit for injection in the gas grid.

## 1.4 Thesis structure

This document is divided in 6 main parts:

- **Part 1 - Introduction** - Contextualization of the work to be developed throughout the project, beginning with explaining the context and relevance of the topic in today's world, the motivations behind the elaboration of this project, the main objectives and the structure of the thesis.
- **Part 2 – Literature review** – Study and review of the already existing literature about the theme of the thesis, with a review of the state-of-the-art technologies and other important key factors.
- **Part 3 – Case study definition** – Presentation of the work to be developed, the objectives and main stages of the project.
- **Part 4 – Methodological approach** – Description of the implementation strategies and the methodology used in this thesis.
- **Part 5 – Analysis of the results** – Presentation and discussion of the results obtained from the application of the methodology to the chosen case study.
- **Part 6 – Conclusions and future work** - Conclusions regarding all the work developed during the project, as well as identification of potential future work.



## 2. Literature review

In order to fully understand the addressed topic and to be able to compare and discuss different solutions for the problem and case of study in question, it is important to be familiarized with all the concepts and strands regarding the main theme this thesis.

This way, the main objective of this chapter is to present a literature review on the current state of hydrogen and its role in the global energy mix. Firstly, in section 2.1, the current state of art of the hydrogen industry will be addressed. In section 2.2, the role of hydrogen strategies from different countries are presented, including the plans and roadmaps that they have regarding the hydrogen industry and the incentives that will be available to try to scale this market. In section 2.3, the main technologies used to produce hydrogen are introduced and compared considering several parameters. Section 2.4 provides an overview of the costs of electrolyzers and the expected costs of producing hydrogen via electrolysis, while section 2.5 looks into the end-use sectors in which green hydrogen can have a direct impact, and the applications it has in these areas. Finally, section 2.6 addresses hydrogen transportation, the main ways to do it and carriers and some of the associated costs.

### 2.1 Hydrogen today

Hydrogen has been an energy vector used for many years now. Hydrogen was used to fuel the first internal combustion engines over 200 years ago. Hydrogen provided lift to balloons and airships in the 18th and 19th centuries, and propelled humanity to the moon in the 1960s. Hydrogen in ammonia fertilizer (from fossil fuels and, earlier, from electricity and water) has helped feed a growing global population. And hydrogen has been an integral part of the energy industry since the mid-20th century, when its use became commonplace in oil refining [7].

In Table 1, presented below, are some physical properties of hydrogen.

*Table 1: Hydrogen physical properties [8].*

|                                   |       |
|-----------------------------------|-------|
| <b>Density [kg/m<sup>3</sup>]</b> | 0,089 |
| <b>HHV [MJ/m<sup>3</sup>]</b>     | 12,7  |
| <b>LHV [MJ/m<sup>3</sup>]</b>     | 10,8  |

Supplying hydrogen to industrial users is now a major business globally. Demand for hydrogen was around 90 Mt H<sub>2</sub> in 2020, having grown 50% since the turn of the millennium, as seen in Figure 4. Almost all this demand comes from refining and industrial uses. Annually, refineries consume close to 40 Mt H<sub>2</sub> as feedstock and reagents or as a source of energy [9].

Demand is somewhat higher (more than 50 Mt H<sub>2</sub>) in the industry sector, mainly for feedstock. Chemical production accounts for around 45 Mt H<sub>2</sub> of demand, with roughly three-quarters directed to ammonia production and one-quarter to methanol. The remaining 5 Mt H<sub>2</sub> are consumed in the direct reduced iron (DRI) process for steelmaking. This distribution has remained almost unchanged since 2000, apart from a slight increase in demand for DRI production [9].

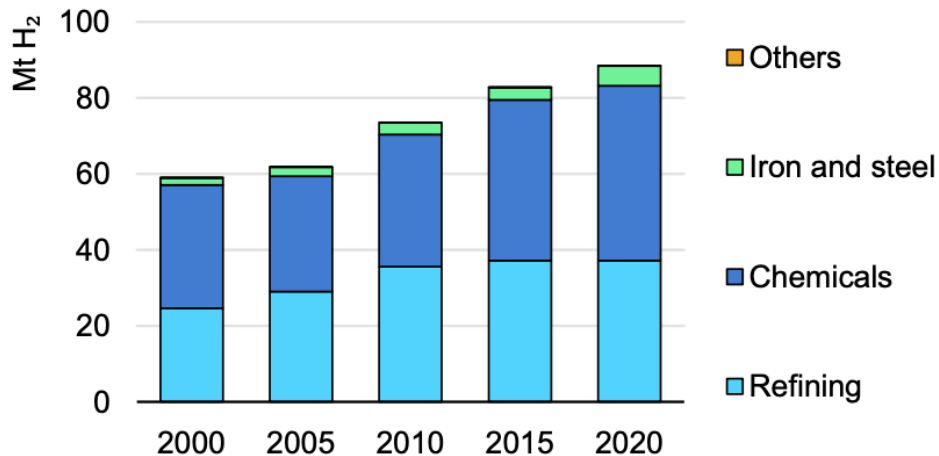


Figure 4: Hydrogen demand by sector, 2000-2020 [9].

This hydrogen demand is almost entirely supplied from fossil fuels and consequently, production of hydrogen is responsible for carbon dioxide (CO<sub>2</sub>) emissions of around 830 million tonnes of carbon dioxide per year (MtCO<sub>2</sub>/yr). In energy terms, total annual hydrogen demand worldwide is around 330 million tonnes of oil equivalent (Mtoe) [7]. For this reason, concerns about climate change have increased and governments and industry are making strong commitments to reduce emissions associated with hydrogen production [9].

The adoption of hydrogen for new applications has been slow, with uptake limited to the last decade, when fuel cell electric vehicle (FCEV) deployment started, and pilot projects began to inject hydrogen into gas grids and use it for electricity generation. Positive results from these experiences prompted the development of some hydrogen technologies to the point of commercialization [9]. These existing markets for hydrogen build on its attributes: it is light, storable, reactive, has high energy content per unit mass, and can be readily produced at industrial scale [7].

Therefore, today's growing interest in the widespread use of hydrogen for clean energy systems rests largely on four additional attributes:

- Hydrogen can be used without direct emissions of air pollutants or greenhouse gases [7];
- It can be made from a diverse range of low-carbon energy sources, including from renewable electricity, biomass and nuclear. Low-carbon production from fossil fuels is also possible, if combined with carbon capture, use and storage (CCUS) and emissions during fossil fuel extraction and supply are mitigated [7];

- Existing applications using hydrogen from fossil fuels can be easily switched to hydrogen produced using alternative, cleaner production methods such as renewable energy sources [7];
- Hydrogen can be used in a wide range of new applications as an alternative to current fuels and inputs, or as a complement to the greater use of electricity in these applications. In these cases – for example in transport, heating, steel production and electricity – hydrogen can be used in its pure form, or converted to hydrogen-based fuels, including synthetic methane, synthetic liquid fuels, ammonia and methanol [7].

Hydrogen has the potential to reinforce and connect different parts of the energy system (sector coupling) as its production allows renewable electricity to be used in applications which are usually better served by fossil fuels and to be stored to meet weekly or monthly imbalances in supply and demand [7].

This way, promoting the use of hydrogen and its deeper penetration in the energy mix is an investment that must continue and must be scaled up in the next years as despite the recent strong momentum, projects currently under development indicate that anticipated hydrogen technology development in demand sectors does not yet align with the net zero emissions scenario's ambitions [9].

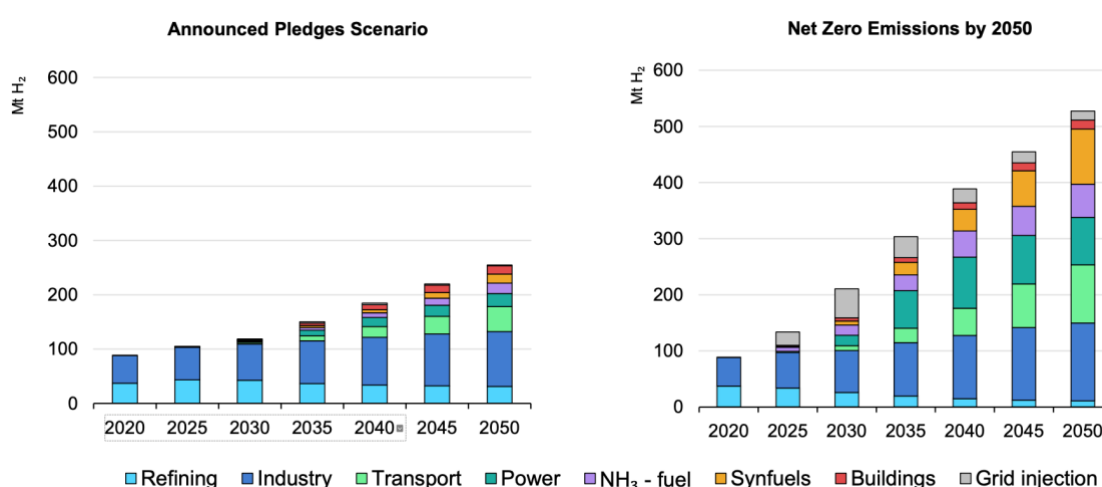


Figure 5: Hydrogen demand by sector in the announced pledges and Net Zero Emissions Scenario (IEA), 2020-2050 [9].

In Figure 5, are shown to graphs with the hydrogen demand from 2020 to 2050, with the left one showing the extent to which the announced ambitions and targets are on the path to deliver emissions reductions required to achieve net zero emissions by 2050. On the other hand, the graph shown on the right, is a scenario that shows a narrow but achievable pathway for the global energy sector to achieve net zero CO<sub>2</sub> emissions by 2050, with the representation a possible path to reach this goal, using hydrogen.

## 2.2 The role of hydrogen strategies

To stabilize or reduce concentrations of CO<sub>2</sub> in the atmosphere, the world needs to reach net-zero emissions as soon as possible. This way and knowing that hydrogen will play a huge role in this process, governments globally support the growth of hydrogen as a clean energy source for the future [10].

In fact, many countries are already defining specific hydrogen strategies in order to reach the net zero carbon ambitions and consolidating their position in the hydrogen market so they can be front runners when hydrogen production starts to scale up.

In Figure 6 are shown a few characteristics of hydrogen production around the world, and also future strategies and goals defined by some countries regarding green hydrogen production.

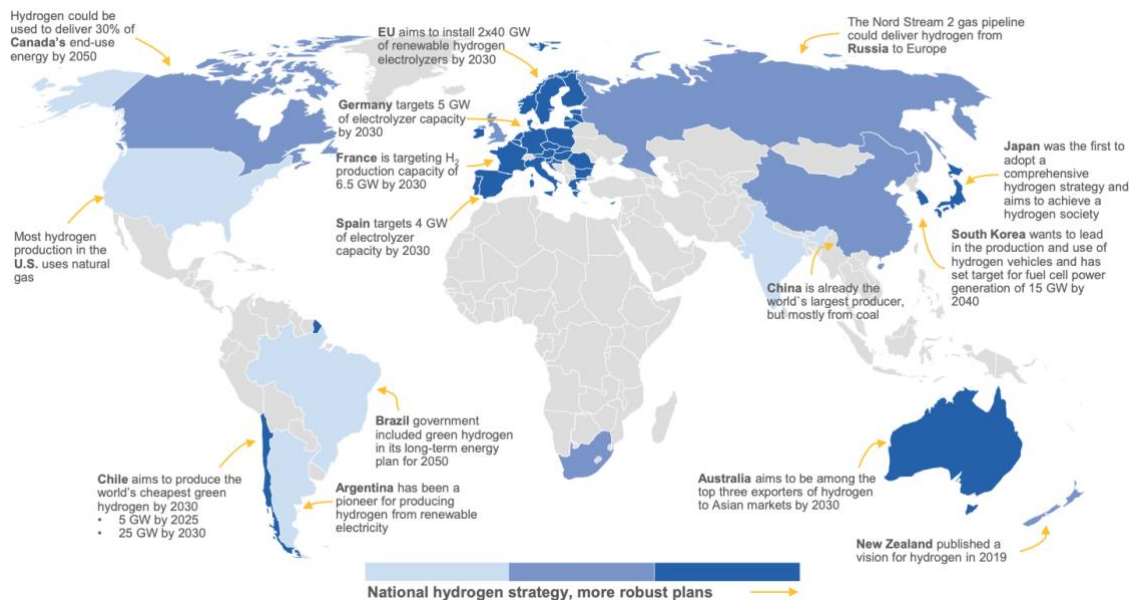


Figure 6: Commitment on hydrogen from countries globally [10].

Recently, hydrogen production from renewable electricity is gaining momentum worldwide. This is fundamental for the advancement of hydrogen technologies and markets, so that green hydrogen competitiveness can increase, and it can become a key resource in the decarbonizing process.

Thus, around the world countries are adopting different strategies to develop and scale hydrogen production from renewable energy sources, based on their resources, investment capacity in new projects and new policies the governments want to put into practice. Some of the countries paving the way to this transition and their respectively main strategies are:

- European Union:
  - A new Hydrogen Accelerator project to ensure 10 million tonnes of domestic renewable hydrogen production and 10 million tonnes of renewable hydrogen imports by 2030 is being launched, including:
    - ◆ New financing for renewable hydrogen projects under Horizon Europe worth 200 million euros and swift approval of projects under the Important Projects of Common European Interest framework [11];
    - ◆ Two new legal acts to complete the regulatory framework and boost the production, consumption and market developments of renewable and low-carbon hydrogen [11];
    - ◆ Accelerate work on technical hydrogen standards, in particular for hydrogen production, infrastructure and end-use appliances [11];
    - ◆ The establishment of a Global European Hydrogen Facility and Green Hydrogen Partnerships to incentivize European and global renewable hydrogen production and trade [11].
  
- Australia:
  - Australia has more than 60 development projects in the hydrogen space (ranging from concept through to generation), and its government is investing A\$1.2 billion in building the country's hydrogen economy, with the aim to build a competitive export industry to position itself as a leading global player [12];
  - South Australia has significant renewable generation capacity and limited interconnection with the rest of the country. It is an ideal site for hydrogen production from solar and wind power and can help with integration of these renewable energy sources. At the same time, significant potential for renewable power generation at low cost exists in areas with very limited electricity demand. Therefore, large-scale facilities can be deployed as fully dedicated to hydrogen production. In the north-west Pilbara region, 15 GW of solar PV and wind is planned. This capacity is aimed primarily at the local iron mining industry but also with an eye to hydrogen exports [13];
  
- Chile:
  - Chile is developing a strategy aimed at exporting hydrogen to countries including Japan and the Republic of Korea. The Chilean hydrogen case leverages one of the best solar resources in the world in regions such as the Atacama Desert, with more than 3 000 sun hours and less than 2 millimeters of rainfall per year, which results in the low-cost, high-capacity renewables essential for low-cost hydrogen production [13];
  - Utilizing a small amount of the solar PV potential in the Atacama Desert could lead to hydrogen production of more than 450 000 tonnes per year [13];
  - Chile has outlined strategies to become by 2025 the top destination for green hydrogen investment in Latin America, have 5GW electrolysis capacity and have 200kton/year produced in at least two production locations [14];
  - For 2030, Chile is planning to be the leader in exports of green hydrogen and derivatives, have the cheapest green hydrogen in the planet (<1,5 USD/kg) and

to be the biggest producer of green hydrogen via electrolysis, with a project of 25GW [14].

- Japan:
  - In Fukushima, a 10 MW electrolyser has been ordered by Toshiba to provide 900 tonnes per year of hydrogen from renewables, to be used for transport applications. Hydrogen is produced from a 20 MW solar PV project. The Japanese strategy also comprises the Yamanashi Fuel Cell Valley which includes a power-to-gas facility utilizing a 1.5 MW PEM electrolysis coupled with a 21 MW solar PV system [13].
- Norway:
  - The Norwegian proposal is hydropower (or wind) paired with high-temperature electrolysis. Hydrogen would then be liquefied for shipment to Japan. The proposal expects to achieve a levelized cost of hydrogen of USD 2.2/kg [13].
- Portugal:
  - Portugal is also working towards the deployment of green hydrogen and creating strategies to develop the technologies needed with this project being divided in 3 phases: phase 1 (2020-2023) where there will be the creation of the regulatory framework and first projects, phase 2 (2024-2030) characterized by the consolidation and roll-out of projects at national level and phase 3 (2030-2050) to fully develop the national hydrogen market [15];
  - The main objectives from 2020 to 2030 are that hydrogen has a 5% weight in the final energy consumption, 5% in the consumption of road transport, 5% in the industry energy consumption, 10-15% blending in the natural gas grid, 50-100 supply stations, 2-2.5 GW capacity in electrolysers, 7000-8000 M€ investment in new projects, 500-550 M€ to support production, 380-740 M€ decrease in natural gas imports, 180 M€ decrease in ammonia imports, 8500-12000 new job positions and a 6 – 8 Mton decrease in CO<sub>2</sub> emissions [15].
- Saudi Arabia:
  - In the future, hydrogen from Saudi Arabia could be produced from a combination of wind and solar PV with the objective of increasing the capacity factor while marginally raising electricity costs. Concentrating solar power can also greatly contribute to increasing the capacity factor and potentially use high-efficiency electrolysis (*e.g.*, the use of heat plus electricity for solid oxide electrolysis cells, SOEC) [13];
  - Saudi Arabia has signalled ammonia as the chosen pathway to transport hydrogen given the existing international experience [13];
  - Based on the latest bids of USD23.4/MWh for a utility-scale solar PV project and USD21.3/MWh for a wind farm (IRENA, 2019g), hydrogen could be

produced today at USD3.95/kg by PV panels (2100 full load hours) and at USD3.31/kg in wind farms (2620 full load hours) [13].

It is clear that regulatory change is needed to support the advancement of hydrogen deployment. If governments are serious about creating a local hydrogen economy and/or being part of a new global hydrogen trading ecosystem, they will need to create the incentive to invest. With some governments already having increased available incentives, it is expected private sector investment to continue to grow, particularly as government regulation and support become clearer [12].

## 2.3 Technologies

Hydrogen as a chemical element (H) is the most widespread one on the earth and as a molecule ( $H_2$ ) can be obtained from almost all energy resources both renewable and nonrenewable by various processes [16].

There is a true rainbow of colors to represent hydrogen depending on its production. Current and future sourcing options include:

- White hydrogen: gaseous naturally formed geological hydrogen found in underground deposits. Hard to find as its odorless and colorless and at the present there are no efficient and economically viable strategies to extract it [17];
- Grey hydrogen: currently the most common form to produce hydrogen, representing about 90% of total production. Natural gas or other fossil fuels are used which, when heated to separate the hydrogen, end up releasing CO<sub>2</sub> into the atmosphere [13,17];
- Blue hydrogen: produced from natural gas, using a process called steam methane reforming, has carbon dioxide as a by-product which is captured via carbon capture and storage (CCS) process. The CO<sub>2</sub> emissions that are not captured, including fugitive emissions during the extraction and transport of natural gas, prevent it from being an environmentally efficient solution [13,17];
- Turquoise hydrogen: experimental technology which production has yet to be proven at scale. The raw material is natural gas or biogas, but this process, known as methane pyrolysis, results in solid carbon rather than the release of CO<sub>2</sub> emissions. This product could then have commercial applications in various industries: tires, paints, steel, graphite [17];
- Pink hydrogen: electrolysis powered by nuclear energy to obtain hydrogen. This process has the risks and nuclear wastes associated with the nuclear technology [17];
- Green hydrogen: electricity from renewable sources of energy is used to power the electrolysis process, resulting in the production of hydrogen without direct pollutant emission during the process. The production of green hydrogen is still expensive, but its cost is expected to drop significantly in the coming years,

which makes it the real hope for several sectors in terms of energy efficiency and positive effects on the environment [13,17].

However, today's hydrogen production is mostly done using by fossil fuels, with significant associated carbon dioxide emissions. As it can be seen in Figure 7, of global hydrogen demand of 90 Mt in 2020, 72 Mt H<sub>2</sub> (around 79%) was produced from dedicated hydrogen production plants relying on fossil fuels. The remainder (21%) was by-product hydrogen produced in facilities designed primarily for other products, mainly refineries in which the reformation of naphtha into gasoline results in hydrogen [9].

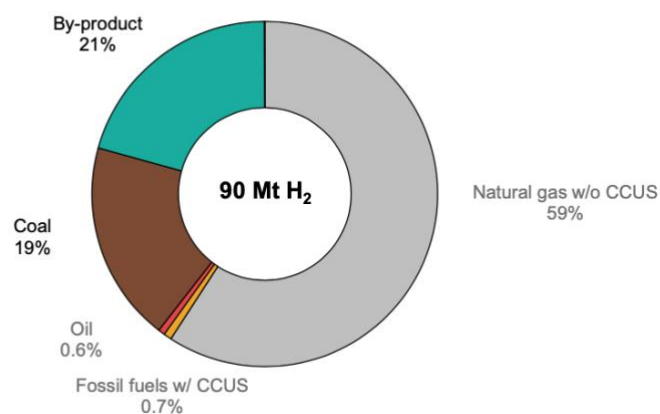


Figure 7: Sources of hydrogen production, 2020 [9].

Today, less than 4% of the hydrogen production is based on electrolysis processes, of which the main part is hydrogen as a by-product of chlorine production. This outlook is mainly caused by the economic disadvantages that the production of hydrogen via electrolysis with renewable energy sources has when compared to its production using fossil fuels, due to high electricity prices, lack of technologies maturity and existing regulations [18].

Therefore, the different ways to produce hydrogen can be separated in two main categories and they are [16,19]:

- HYDROGEN FROM FOSSIL FUELS:
  - Steam reforming (SR);
  - Partial oxidation (POX);
  - Autothermal reforming (ATR);
  - Plasma reforming.
- HYDROGEN FROM RENEWABLE SOURCES:
  - Biomass gasification;

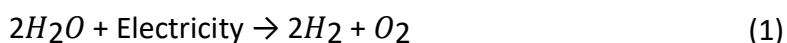
- Aqueous phase reforming;
- Electrolysis;
- Photolysis;
- Thermochemical water splitting.

In Table 2 are presented some characteristics of the technologies presented above.

*Table 2: Hydrogen production technologies summary [16,19].*

| <b>Technology</b>                     | <b>Feedstock</b>     | <b>Efficiency</b> | <b>Maturity</b> |
|---------------------------------------|----------------------|-------------------|-----------------|
| <b>Steam reforming</b>                | Hydrocarbons         | 70 – 85 %         | Commercial      |
| <b>Partial oxidation</b>              | Hydrocarbons         | 60 – 75 %         | Commercial      |
| <b>Autothermal reforming</b>          | Hydrocarbons         | 60 – 75 %         | Near term       |
| <b>Plasma reforming</b>               | Hydrocarbons         | 9 – 85 %          | Long term       |
| <b>Biomass gasification</b>           | Biomass              | 35 – 50 %         | Commercial      |
| <b>Aqueous phase reforming</b>        | Carbohydrates        | 35 – 55 %         | Medium term     |
| <b>Electrolysis</b>                   | $H_2O$ + Electricity | 50 – 70 %         | Commercial      |
| <b>Photolysis</b>                     | $H_2O$ + Sunlight    | 0,5 %             | Long term       |
| <b>Thermochemical water splitting</b> | $H_2O$ + Heat        | Not available     | Long term       |

Considering the characteristics of the different pathways, the production of hydrogen using electrolysis is expected to dominate in the future, owing to the higher efficiency and availability of resources to produce renewable electricity. Electrolysis is the process of separating water into hydrogen and oxygen, which requires electricity to happen, as shown in reaction (1). In this process, an electrolyser is used to decompose water and to produce the so-called green hydrogen, the electricity needed must be from renewable energy sources.



When it comes to the electrolyzers used in the process they range in size and function and can be scaled to meet different input and output values, ranging in size from small industrial plants of just a few kW of power to large scale centralized production facilities that may reach over 1GW. They are also distinguished based on the

electrolyte and temperature of operation, which in turn will guide the selection of different materials and components [1].

Water electrolyzers are electrochemical devices that can be fragmented in three key components: the cell, the stack and the system level. The cell is the center piece of the electrolyzer as it is where the electrochemical reactions take place. The stack includes multiple cells connected in series with components such as frames that provide mechanical support to the stack and end plates that avoid leaks. Lastly, the system level (or balance of plant) goes beyond the stack to include equipment for cooling and processing the hydrogen, converting the electricity input, treating the water supply and the gas output [1]. Figure 8 shows a representation of these different parts of the electrolyzer.

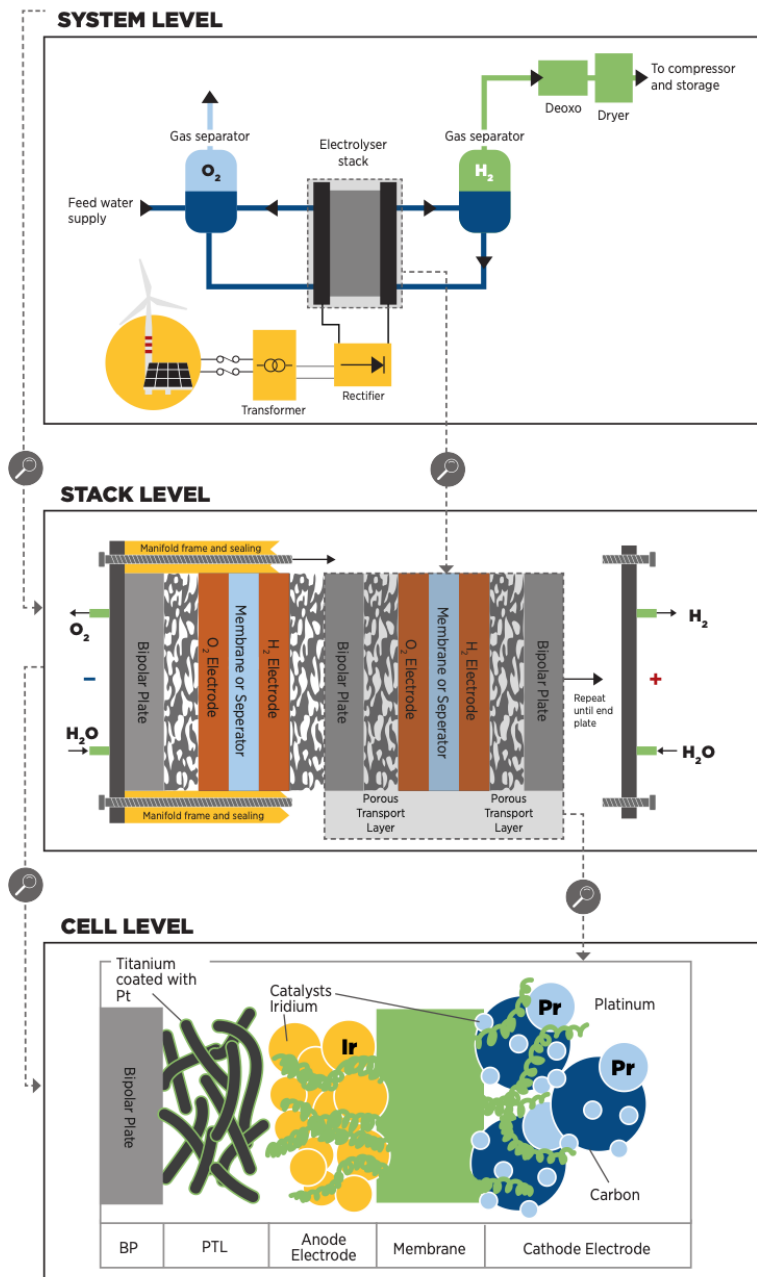


Figure 8: Basic components of water electrolyzers at different levels [1].

There are four different electrolyser technologies that will be listed below, where the first two are already commercial and provide high technology readiness levels while the last two are now at a lab scale and promise a major step forward [1,18]:

- Alkaline electrolyzers (ALK)
- Proton exchange membrane electrolyzers (PEM)
- Solid oxide electrolyzers (SOEC)
- Anion exchange membrane electrolyser (AEM)

### **ALKALINE ELECTROLYSERS (ALK):**

Alkaline electrolyzers are the most common type available commercially and the most established technology on the market, as they are the most mature technology and present a high lifetime and low maintenance costs. The hydrogen is produced in cells constituted by a pair of electrodes immersed in an alkaline solution and separated by a diaphragm [20].

Some key characteristics of the alkaline electrolyzers are:

- The electrodes are typically made of steel, nickel, or nickel-plated steel [21];
- The alkaline solution, which is the electrolyte, is an aqueous solution usually of potassium hydroxide (KOH) at a concentration of 25-30% [22];
- The separator of the electrodes compartments is a micro-porous diaphragm that prevents the blending of different gases to avoid recombination. This barrier must be permeable to hydroxide ions and water and is usually made from zirconium dioxide ( $\text{ZrO}_2$ ) [1,21].

The functioning of an alkaline electrolyser starts with the supply of water to the cathode and when electrical power is applied to the cells, the electrons received from the external circuit cause water to split in hydrogen and  $\text{OH}^-$ . The hydroxide ions ( $\text{OH}^-$ ) are transported across the separation to the anode so that oxygen and hydrogen are formed as can be seen in Figure 9 [23].

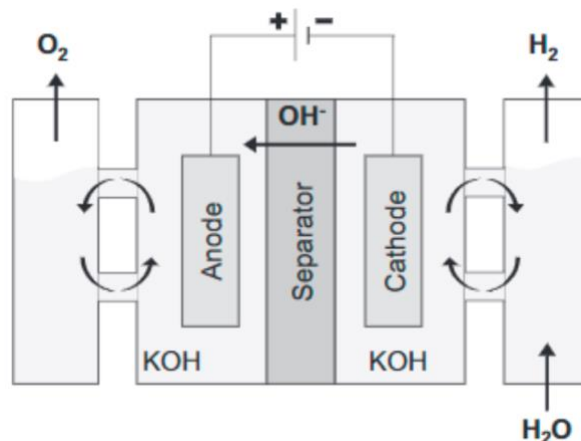


Figure 9: Working principle of an alkaline electrolyser [21].

During this process, the reactions that occur at the cathode and anode are given by the reactions (2) and (3) respectively:



### **PROTON EXCHANGE MEMBRANE ELECTROLYSERS (PEM):**

Proton exchange membrane electrolyzers are commercially available today and are rapidly gaining market traction as, among other factors, they are more flexible and have a smaller footprint, combined with higher current density and output pressure [1]. State-of-the-art PEM electrolyzers can operate more flexibly and reactively than current alkaline technology. This offers a significant advantage in allowing flexible operation to capture revenues from multiple electricity markets, as PEM technology offers a wider operating range and has a shorter response time [2].

Proton membrane electrolyzers offer several advantages when compared to conventional alkaline electrolyzers such as higher efficiency and higher purity of the hydrogen gas produced, which is important to many applications [24]. These benefits come however with more complex and special components of the electrolyser, as the expensive polymer membrane, porous electrodes, and current collectors [24]. Some of the characteristics of these components are:

- Two electrodes are in contact with a proton exchange polymer electrolyte membrane, forming a membrane electrode assembly (MEA) [21];
- The materials of this membrane are typically perfluorosulfonic polyfluorosulfonic acids (PFSA) such as Nafion [21,25];
- This membrane has not only the function of separating the electrodes but also works as a gas separator [19]. This membrane is also chemically and mechanically robust, which allows for high pressure differentials [1];
- Typically, the membranes are catalyst coated and contacted by either expanded metal meshes or carbon or metallic felts [21];
- The most common catalysts used commercially have a platinum cathode, as these have demonstrated to be very effective for long operating times with different types of electrodes and for the anode iridium oxide ( $IrO_2$ ) catalysts are the most common [21,25];
- PEMs have one of the most compact and simplest system designs, yet they are sensitive to water impurities such as iron, copper, chromium and sodium and can suffer from calcination [1].

As shown in Figure 10, in proton exchange membrane electrolyzers water is introduced at the anode where it splits into oxygen and protons when electricity is supplied to the system. The  $H^+$  protons travel through the membrane to the cathode

side where they combine with electrons to form hydrogen. The oxygen gas remains behind with the unreacted water [19,24]. Depending on the purity requirements a drier may be used to remove residual water after a gas/liquid separations unit [19].

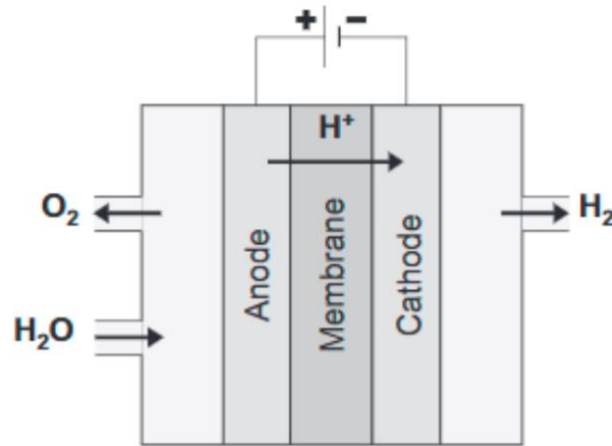


Figure 10: Working principle of a PEM electrolyser [21].

Hydrogen production with PEM electrolyzers can be carried out both at low and high pressure. When comparing each method in terms of cost effectiveness and total power required there are some advantages in high pressure electrolysis in part because of the elimination of hydrogen compression from the process which contributes significantly to cost and power savings [24]. In fact, it is reported that the power required to produce hydrogen by high-pressure water electrolysis is about 5% less than that required for atmospheric water electrolysis [26].

The reactions (4) and (5) presented below are the overall reactions that happen at the anode and cathode, respectively:



### **SOLID OXIDE ELECTROLYSERS (SOEC):**

Solid oxide electrolyzers are a more recent technology whose functioning is based on the replacement of part of the electrical energy used to split water with thermal energy [19]. The main difference of this type of electrolyser when compared to the ones talked above is the fact that in this case the system operates at high temperatures, usually at temperatures in the range of 700-850 °C [27].

Due to the high temperatures at which they operate, SOEC technologies use water steam (instead of liquid water) and are thus a consumer of heat, rather than a producer of heat [21].

The high operating temperatures of these electrolyzers lead to:

- The favorable kinetics that allow the use of relatively cheap nickel electrodes [1];
- As part of the energy for separation is provided through heat, waste heat can be used and apparent electric efficiencies can be higher than 100% [1];
- The power for reversibility (operating as fuel cell and electrolyser) [1];
- Co- electrolysis of CO<sub>2</sub> and water to produce syngas [1];
- Thermo-chemical cycling, especially under shutdown/ramping periods, leads to faster degradation and shorter lifetimes [1];
- Other issues related to stack degradation such as electrode contamination [1].

The electrolyte (membrane) is a dense layer of a solid ceramic material, commonly yttria stabilized zirconia (YSZ) [19,21].

In Figure 11, the working principles of SOEC technologies are shown, which begins with the supply of water steam to the cathode where hydrogen gas and negative charge oxygen ions are formed. Then these ions go through the solid electrolyte to the anode side where they recombine into oxygen gas molecules, releasing electrons [28].

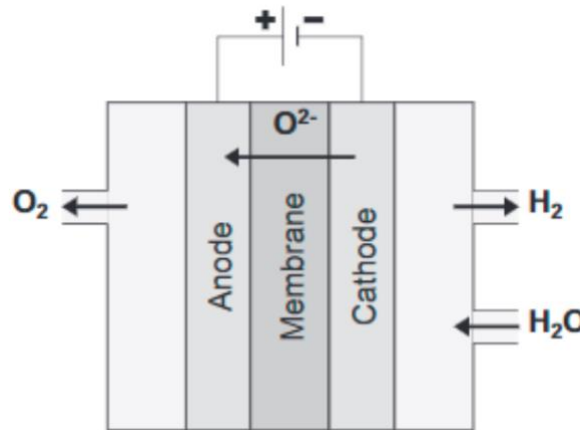


Figure 11: Working principle of a solid oxide electrolyser [21].

The reactions that take place during this process at the cathode and anode are given by the reactions (6) and (7) respectively:



### ANION EXCHANGE MEMBRANE ELECTROLYSER (AEM):

Anion exchange membrane is the latest electrolyser technology launched with still very limited deployment. AEM's potential lies in the combination of a less harsh environment from alkaline electrolysers with the simplicity and efficiency of a PEM electrolyser [1].

Its functioning allows the use of non-noble catalysts and titanium-free components and operation under differential pressures. However, because the technology is still under development, the AEM membrane has chemical and mechanical stability problems which leads to unstable and unreliable lifetime profiles. Besides this, the performance of the electrolysers is still not as good as expected mostly due to the membrane conductivity, poor electrode architectures and slow catalyst kinetics. Performance enhancement is typically achieved by tuning membrane conductivity properties, or by adding a supporting electrolyte. Such tuning could lead to decreased durability, however [1].

The operating process of an anion exchange membrane electrolyser is illustrated in Figure 12, where the water is circulated through the cathode side where it is reduced to form hydrogen and hydroxyl ions ( $\text{OH}^-$ ) by the addition of electrons. These ions diffuse through the AEM membrane to the anode side by the positive attraction of the anode. At the anode the  $\text{OH}^-$  ions recombine as water and oxygen by losing electrons [29].

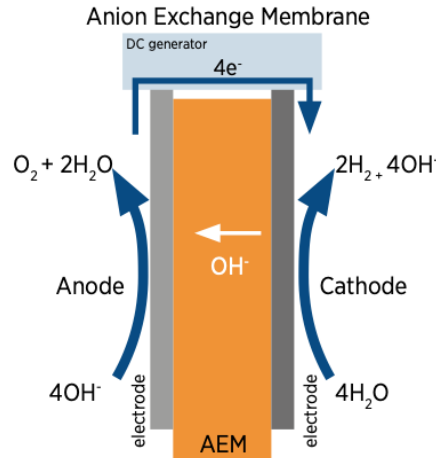


Figure 12: Working principle of an anion exchange membrane electrolyser [1].

The reactions that take place during this process at the anode and cathode are given by the reactions (8) and (9) respectively:



## TECHNOLOGIES COMPARISON:

Considering the main characteristics of each type of electrolyser, it is clear that each technology has its own benefits and challenges, from critical materials to performance, durability and maturity. There is no clear winner across all applications, which leaves the door open for competition and innovation driving costs down [1].

In Table 3, beyond the operating temperatures and pressures of the technologies, some of the structural and material characteristics mentioned above are presented. The cells colored in blue represent conditions or components with significant variations among different companies and manufactures [1].

Table 3: Characterization of the four types of water electrolyzers [1].

|                                      | Alkaline                                            | PEM                                      | AEM                                                                          | Solid Oxide                      |
|--------------------------------------|-----------------------------------------------------|------------------------------------------|------------------------------------------------------------------------------|----------------------------------|
| Operating temperature                | 70-90 °C                                            | 50-80 °C                                 | 40-60 °C                                                                     | 700-850 °C                       |
| Operating pressure                   | 1-30 bar                                            | < 70 bar                                 | < 35 bar                                                                     | 1 bar                            |
| Electrolyte                          | Potassium hydroxide (KOH)<br>5-7 molL <sup>-1</sup> | PFSA membranes                           | DVB polymer support with<br>KOH or NaHCO <sub>3</sub><br>1molL <sup>-1</sup> | Yttria-stabilized Zirconia (YSZ) |
| Separator                            | ZrO <sub>2</sub> stabilized with PPS mesh           | Solid electrolyte (above)                | Solid electrolyte (above)                                                    | Solid electrolyte (above)        |
| Electrode / catalyst (oxygen side)   | Nickel coated perforated stainless steel            | Iridium oxide                            | High surface area Nickel or NiFeCo alloys                                    | Perovskite-type (e.g. LSCF, LSM) |
| Electrode / catalyst (hydrogen side) | Nickel coated perforated stainless steel            | Platinum nanoparticles on carbon black   | High surface area nickel                                                     | Ni/YSZ                           |
| Porous transport layer anode         | Nickel mesh (not always present)                    | Platinum coated sintered porous titanium | Nickel foam                                                                  | Coarse Nickel-mesh or foam       |
| Porous transport layer cathode       | Nickel mesh                                         | Sintered porous titanium or carbon cloth | Nickel foam or carbon Cloth                                                  | None                             |
| Bipolar plate anode                  | Nickel-coated stainless steel                       | Platinum-coated titanium                 | Nickel-coated stainless steel                                                | None                             |
| Bipolar plate cathode                | Nickel-coated stainless steel                       | Gold-coated titanium                     | Nickel-coated Stainless steel                                                | Cobalt-coated stainless steel    |
| Frames and sealing                   | PSU, PTFE, EPDM                                     | PTFE, PSU, ETFE                          | PTFE, Silicon                                                                | Ceramic glass                    |

In addition to these features, there are some key performance indicators of the electrolyzers that must be considered. Today's cost and performance are not the same for all types of technologies, but these gaps are expected to narrow over time as innovation and mass deployment of different electrolysis technologies drive convergence towards similar costs. The wide range in system costs is expected to remain, however, as this is very much dependent on the scale, application and scope of delivery [1].

Consequently, Table 4 presents some performance indicators for the different electrolyser technologies today and in 2050 and, as can be seen and expected, the

increase in efficiency and lifetime of the electrolyzers is accompanied by a decrease in their price.

Table 4: Key performance indicators for four electrolyser technologies today and in 2050 [1].

|                                                                                      | 2020     |          |       |         | 2050     |         |       |       |
|--------------------------------------------------------------------------------------|----------|----------|-------|---------|----------|---------|-------|-------|
|                                                                                      | Alkaline | PEM      | AEM   | SOEC    | Alkaline | PEM     | AEM   | SOEC  |
| Cell pressure [bara]                                                                 | < 30     | < 70     | < 35  | < 10    | > 70     | > 70    | > 70  | > 20  |
| Efficiency (system) [kWh/KgH <sub>2</sub> ]                                          | 50-78    | 50-83    | 57-69 | 45-55   | < 45     | < 45    | < 45  | < 40  |
| Lifetime [thousand hours]                                                            | 60       | 50-80    | > 5   | < 20    | 100      | 100-120 | 100   | 80    |
| Capital costs estimate for large stacks (stack-only, > 1 MW) [USD/kW <sub>el</sub> ] | 270      | 400      | -     | > 2 000 | < 100    | < 100   | < 100 | < 200 |
| Capital cost range estimate for the entire system, >10 MW [USD/kW <sub>el</sub> ]    | 500-1000 | 700-1400 | -     | -       | < 200    | < 200   | < 200 | < 300 |

These changes are mostly caused by the standardization and simplification of the manufacturing process which allows industrialization and scale-up, an improvement in efficiency which reduces the amount of electricity required to produce one unit of hydrogen and an increase durability to extend the equipment lifetime and spread the cost of the electrolyser facility over a larger hydrogen production volume [1].

## 2.4 Cost estimation

As mentioned before, electricity represents the main cost of the green hydrogen production, as its price is still really high and therefore an obstacle for this technology's competitiveness. In fact, electricity costs account for 50-90% of the overall cost of hydrogen production [9].

Using grid electricity is often rather expensive, with electricity prices of USD 50-100/MWh resulting in hydrogen production costs of around USD 3.00-5.00/kg H<sub>2</sub> (at

an electrolyser capacity factor of 90%). In contrast, co-locating hydrogen production with dedicated electricity generation from renewables often avoids or minimizes electricity transmission costs. Renewable electricity is thus the dominant source for hydrogen projects currently under construction or being planned [9].

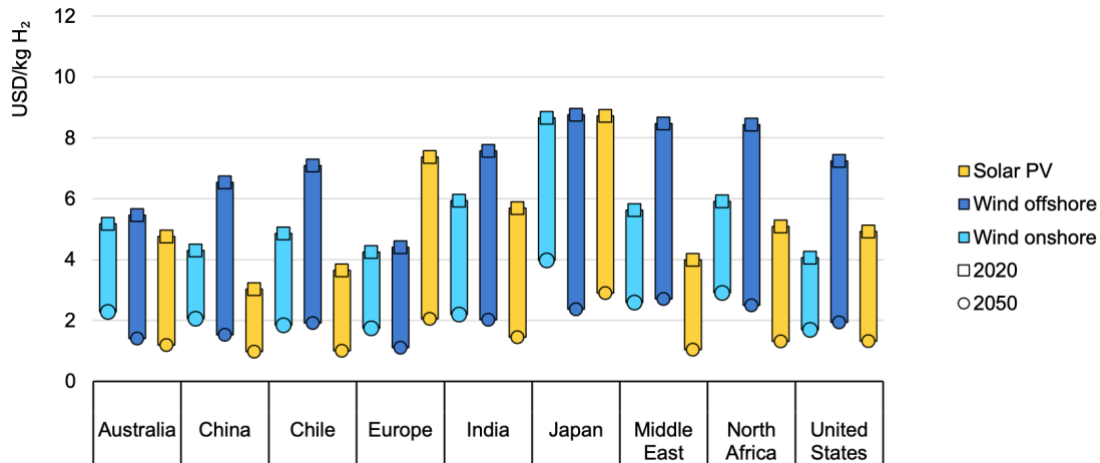


Figure 13: Levelized cost of hydrogen production from renewables by technology and region in the Net Zero Emissions Scenario (IEA), 2020 and 2050 [9]

As can be seen in Figure 13, solar PV has become one of the most affordable energy sources for electricity generation, and in locations with excellent solar conditions, prices of electricity around USD 20/MWh can originate lower hydrogen production costs. In fact, with solar PV and electrolyser costs decreasing in the Net zero Emissions Scenario, which is a normative IEA scenario, hydrogen production via solar PV could cost less than USD 1.50/kg H<sub>2</sub> in 2030 and reach values of USD 1.00/kg H<sub>2</sub> by 2050, making hydrogen from solar PV cost-competitive with natural gas [9].

At USD 60/MWh, electricity generation from offshore wind was relatively costly in 2020, resulting in hydrogen costs in the range of USD 4.50/kg H<sub>2</sub> (at a 50% capacity factor). With declining costs for offshore electricity generation (USD 30/MWh) and larger turbines resulting in higher capacity factors, hydrogen production costs in the Net zero Emissions Scenario could fall to USD 2.00/kg H<sub>2</sub> by 2030 and to below USD 1.50/kg H<sub>2</sub> by 2050 (based on electricity costing USD 25/MWh and a capacity factor of 60%) [9].

As mentioned before, besides the price of electricity, the manufacturing price of the electrolysers also represents a considerable percentage of the production costs of green hydrogen.

In 2020, electrolysers costs fell within the range of USD 1000-1 750/kW, including electric equipment, gas treatment, plant balancing, engineering and construction (EPC), with the lower cost applying to alkaline electrolysers produced in China and the upper representing PEM electrolysers [9].

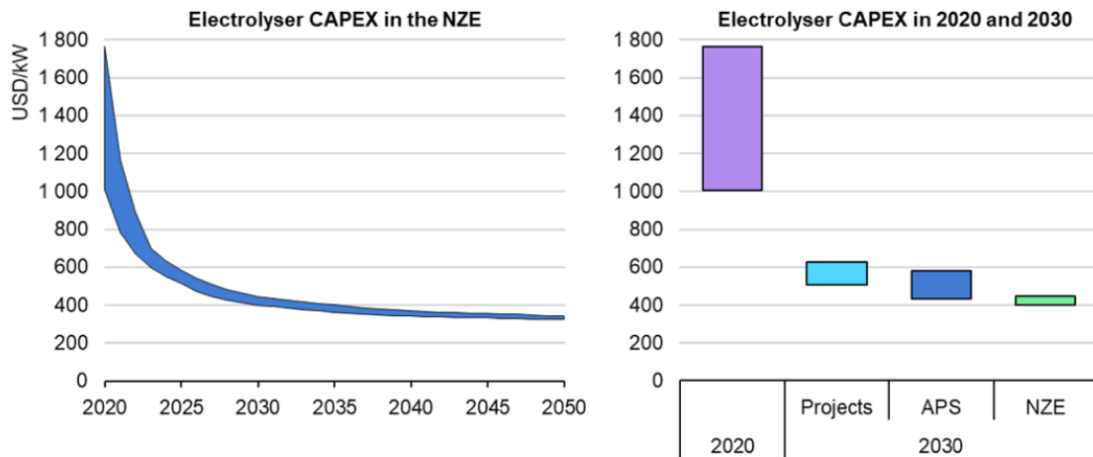


Figure 14: Evolution of electrolyser capital costs under the Project case, Announced Pledges and Net zero Emissions Scenario (IEA) [9].

The cost decrease predictions that can be seen in Figure 14, are based not only on the growth of the learning rates and economies of scale that will happen over time but also on the cumulative capacity deployment of projects under construction and planned that would reduce capital expenses by almost 60% by 2030 [9].

PEM water electrolyzers are 50-60% more expensive than alkaline, and in both technologies the stack is still the main contributor to the system cost representing 40-50% of the final price. This share greatly depends on design, manufacturing strategy, business case and customer specifications [1].

Figure 15 and Figure 16 show a breakdown of cost components for alkaline and PEM electrolyzers respectively.

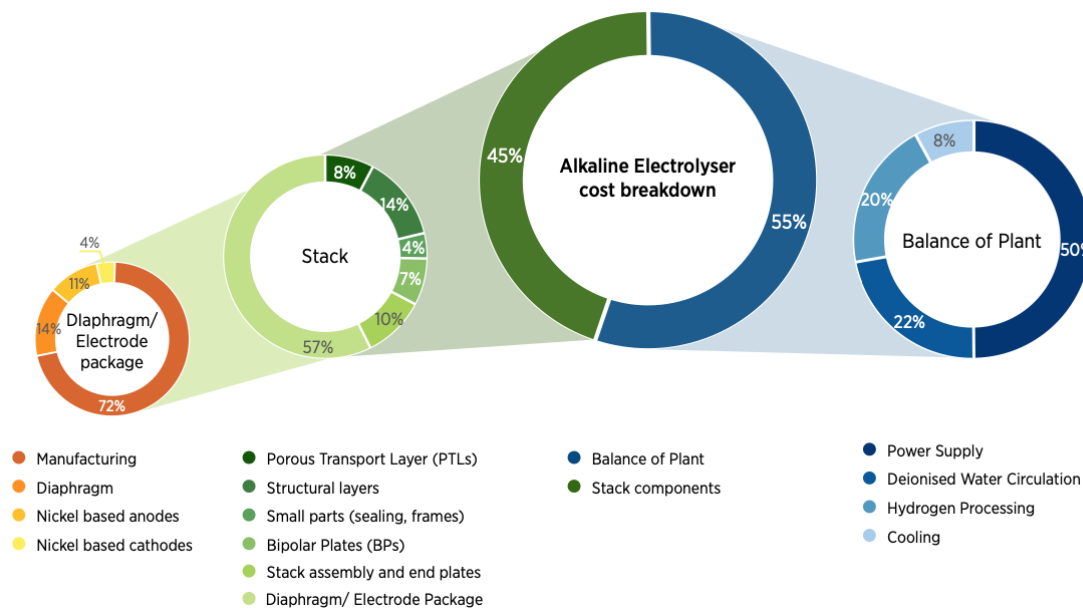


Figure 15: Cost breakdown for 1MW alkaline electrolyser, moving from full system, to stack, to membrane electrode assembly (MEA) [1].

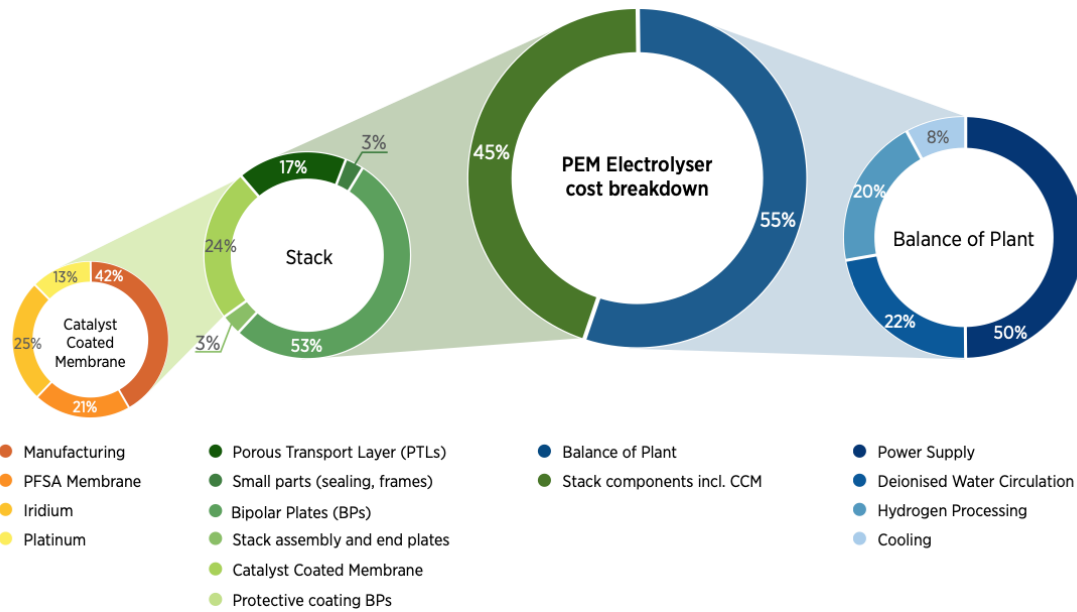


Figure 16: Cost breakdown for a 1MW PEM electrolyser, moving from full system, to stack, to catalyst coated membrane (CCM) [1].

As cost reduction is the key step towards increasing the competitiveness of the hydrogen technologies, in Figure 17 and Figure 18 are presented the potential cost reduction of the various items in order to identify priority areas for innovation and deployment of alkaline and PEM technologies respectively.

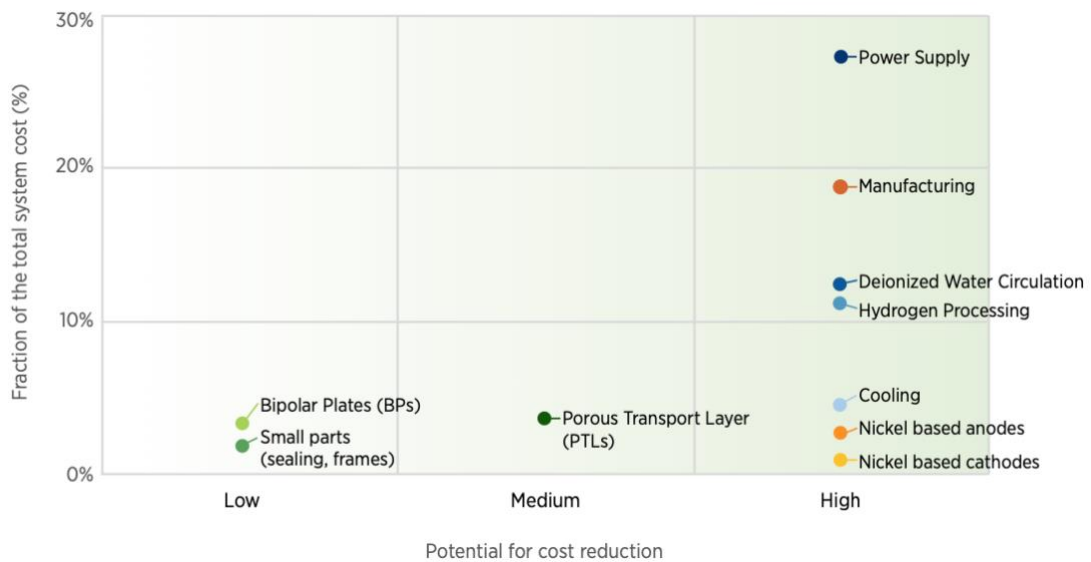


Figure 17: System components for a 1MW alkaline electrolyser, classified based on contribution to total system cost and potential for cost reduction [1].



Figure 18: Systems components for a 1MW PEM electrolyser, classified based on contribution to total system cost and potential for cost reduction [1].

## 2.5 Hydrogen applications in end-use sectors

The flexibility hydrogen has as a feedstock and generally as an energy carrier make it an important element in today's imminent energy transition. Therefore, there are several end use sectors that will benefit with the growth and scale up of the hydrogen market, as shown in Figure 19.

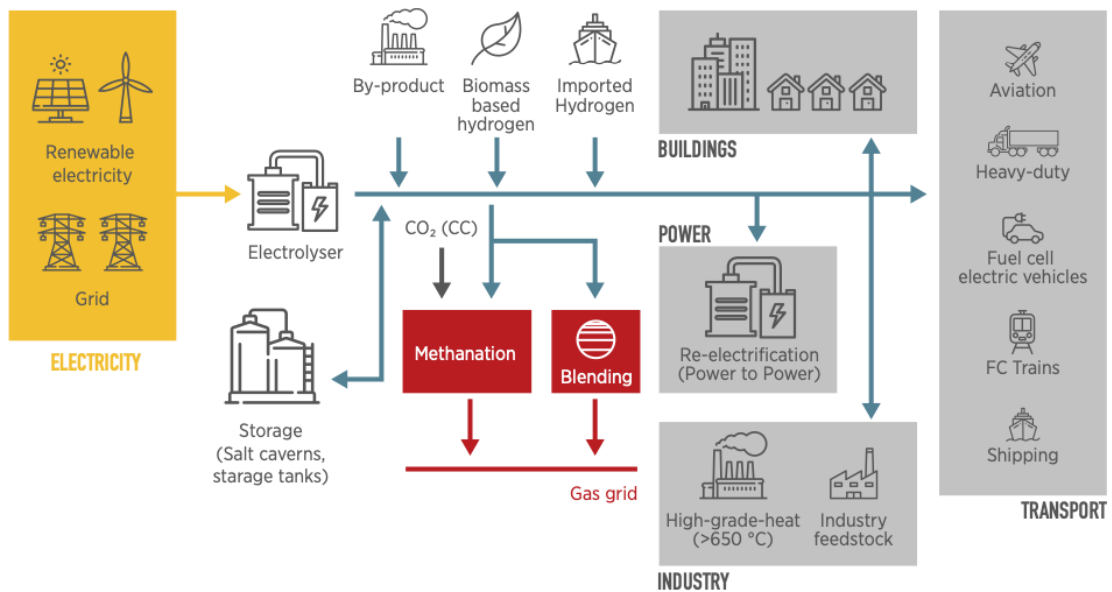


Figure 19: Integration of renewables into end uses by means of hydrogen [2].

### 2.5.1 Transport

Today, the transport sector is responsible for over 20% of the greenhouse gas emissions and 25% of final energy demand, with oil products supplying 90% of the energy it consumes [9].

The preferable path to low CO<sub>2</sub> emissions has become clear for some but not all transport modes. Electrification is a viable option for rail and light-duty road transport, assuming that the electricity comes from renewable sources. In the case of rail transport, the use of electricity is already widespread, especially for passenger transport. In the case of light-duty road transport, battery electric vehicles have shown dramatic improvements in range (kilometers/charge), cost and market share in recent years [30].

For other transport modes, however, the optimal pathway has yet to become clear. Road freight transport, aviation and shipping are significant energy users and CO<sub>2</sub> emitters, and driving their emissions to zero will be a challenge [30].

Hydrogen and hydrogen-based fuels can be important to decarbonize and reduce emissions in this sector, especially in hard-to-electrify segments, such as long-haul, heavy-duty trucking, shipping and aviation, yet this is far from today's reality where not even 0,01% of energy consumed in the transport sector comes from hydrogen [9].

This way, fuel cell electric vehicles (FCEVs), like battery electric vehicles, use electricity to power an electric motor. The difference is that the electricity is produced by a fuel cell powered by compressed hydrogen gas instead of relying on a battery. These vehicles have a fuel tank onboard which has to be filled in a hydrogen charging station. FCEVs do not have harmful tailpipe emissions – they only emit water and heat – and therefore are an option to achieve zero emissions in the transport sector, as long as they use green hydrogen [30].

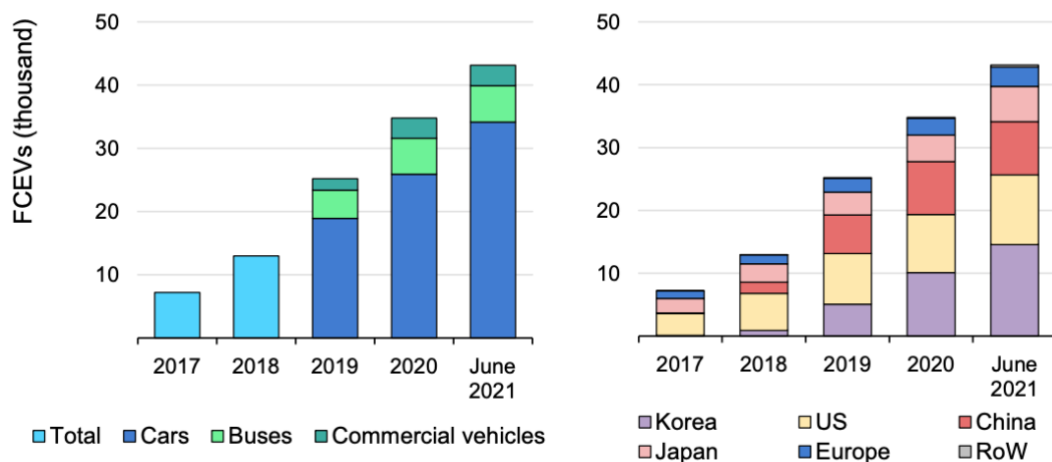


Figure 20: Fuel cell electric vehicle stock by segment and region, 2017 - June 2021 [9].

As can be seen in Figure 20, cars account for the vast majority of fuel cell power deployed in road transport [7]. However, buses and road freight as they are more directed to long-haul transport have a big potential in the fuel cell electric vehicles market, as this technology may allow for longer ranges than battery electric vehicles. Existing fuel cell electric long-haul trucks have a range of 1 100 kilometers, compared to the 400-800 kilometers range of their battery electric counterparts. A limited number of heavy-duty FCEV fleets are already in operation [30].

In the aviation sector, hydrogen fuel cells can have an important role for flights up to 1600 km, and hydrogen combustion for short flights and potentially for medium-haul ones. Assuming the technology is developed successfully, hydrogen fuel cells could be used in 75% of commercial flights but account for approximately only 30% of aviation fuel [9]. Synthetic aviation fuels produced from green hydrogen could also play a role in decarbonizing longer-haul flights, despite the main barrier for scale-up and widespread use of synthetic fuels which is their relatively high costs [30].

In the shipping industry, hydrogen and e-fuels, produced by synthetizing CO<sub>2</sub> and green hydrogen, could play an important role in the decarbonizing process. While their adoption would require substantial adaptations to existing onboard and onshore infrastructure, and thus costs, a complete decarbonization of the sector might not be possible without them [30].

Due to the low volumetric density of hydrogen, direct use of hydrogen will be limited to short and medium-range vessels, especially those with high power requirements that cannot be met through battery electrification. Hydrogen-based fuels are also attracting attention for use as maritime fuels for large oceangoing vessels. Green ammonia, in particular, can be used in internal combustion engines to eliminate vessel CO<sub>2</sub> emissions. Major industry stakeholders have announced plans to make 100% ammonia-fuelled maritime engines available as early as 2023 and to offer ammonia retrofit packages for existing vessels from 2025 [9].

Lastly, the rail sector is already the most electrified mode of transport [7]. Under optimistic assumptions about fuel cell cost reductions, hydrogen trains could become competitive against other passenger services options. Hydrogen fuel cell technology is most competitive for services requiring long- distance movement of large trains with low-frequency network utilization, a common set of conditions in rail freight [7].

## 2.5.2 Industry

In the short term, large industrial sectors where hydrogen has been used for decades, such as refineries and ammonia production are expected to be key early markets for green hydrogen deployment in the industrial sector, as they would be able to generate immediate scale effects and hence rapid cost reductions. In the long term, hydrogen produced from renewable energy via electrolysis has the potential to contribute to the deep decarbonization of other industrial energy uses [2].

Accounting for 38% of total final energy demand, industry is the largest end-use sector and accounts for 26% of global energy system CO<sub>2</sub> emissions. Across industry, 6% of total energy demand is used to produce hydrogen [9], and the top four single uses of hydrogen 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%), all usages connected to the industry sector [7].

Hydrogen demand has been growing over the years and especially in the industry sector it is expected to continue to grow, as an increase of 30% is expected by 2030 and by 2050 the hydrogen demand is predicted to double from today [9]. In 2020, the demand for pure hydrogen in the industry sector was 87.1 Mt and the main uses for it can be seen in Figure 21.

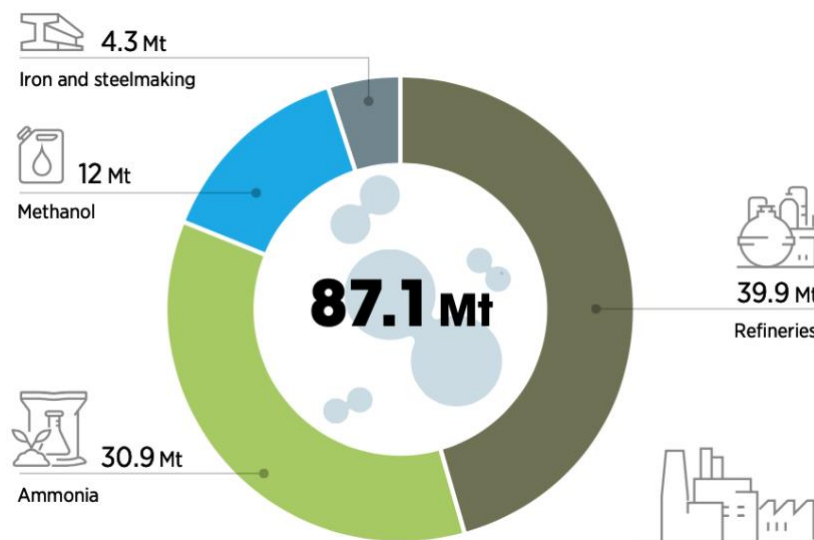


Figure 21: Pure hydrogen demand in industry, global, 2020 [4].

This high applicability of hydrogen in industry is especially evident in these 4 sectors:

- Refineries:
  - Hydrocracking and hydrotreatment are the main hydrogen-consuming processes in refining [7];
  - Hydrocracking consists in converting heavy and low-quality gas oil into more valuable fuels in the presence of hydrogen and a catalyst and is used to maximize fuel production while reducing residual fuel oil [4];
  - Hydrotreatment is the process of mixing hydrogen with fossil gas or refined petroleum products to remove sulphur and other contaminants [4];
  - It is expected a 7% increase in hydrogen demand by 2030 boosted by tighter pollutant regulations, and despite being highly dependent on future oil demand is likely to remain a large source of demand in 2050 [7].

- Chemical industry:
  - Hydrogen is used to produce ammonia, methanol and other chemicals. Since hydrogen is already an essential component of these chemicals, the integration of green hydrogen requires limited modification, based only on changing the process for obtaining it [4];
  - By 2030, is expected a 31% increase in hydrogen demand, under existing policies for ammonia and methanol production, due to economic and population growth [7];
  - Hydrogen demand for existing uses set to grow, new ammonia and methanol demand could arise for clean uses as hydrogen-based fuels [7].
  
- Iron and steel production:
  - 7% of primary steel production occurs via direct reduction of iron (DRI) route, which requires hydrogen [7];
  - Hydrogen is used for annealing - heat treatment of processed metal to restore ductility after deformation [2];
  - By 2030, the hydrogen demand is set to double, under existing policies, as the DRI route is used more, relative to the currently dominant blast furnace route [7];
  - As the steel demand keeps rising, even after accounting for increased materials efficiency, in the long term, 100% hydrogen-based production could dramatically increase demand for low carbon hydrogen [7].
  
- High temperature heat:
  - Industries need heat for various processes. Industrial heat can be classified as high, medium or low, with high-temperature heat above 400°C, medium-temperature heat between 100°C and 400°C, and low-temperature heat below 100°C. Hydrogen combustion produces high-grade heat that meets almost all heavy industrial applications, as shown in Figure 22 [4];
  - Electricity can also be used for high temperature heat, however, the electrification of high-grade heating entails redesigning industrial equipment and, therefore, capital expenditure. Industrial operators may thus prefer less invasive options, such as hydrogen, that involve minimal redesign [4];
  - Today, there is almost no dedicated hydrogen production for generating heat, some limited use using hydrogen containing off gases from the iron and steel and chemical sectors [7];
  - High-temperature heat demand will have a 9% increase by 2030 and is expected to continue to rise even further providing an opportunity for hydrogen if it can compete on cost in the prevailing policy environment and if significant policy supports are put in place [7].

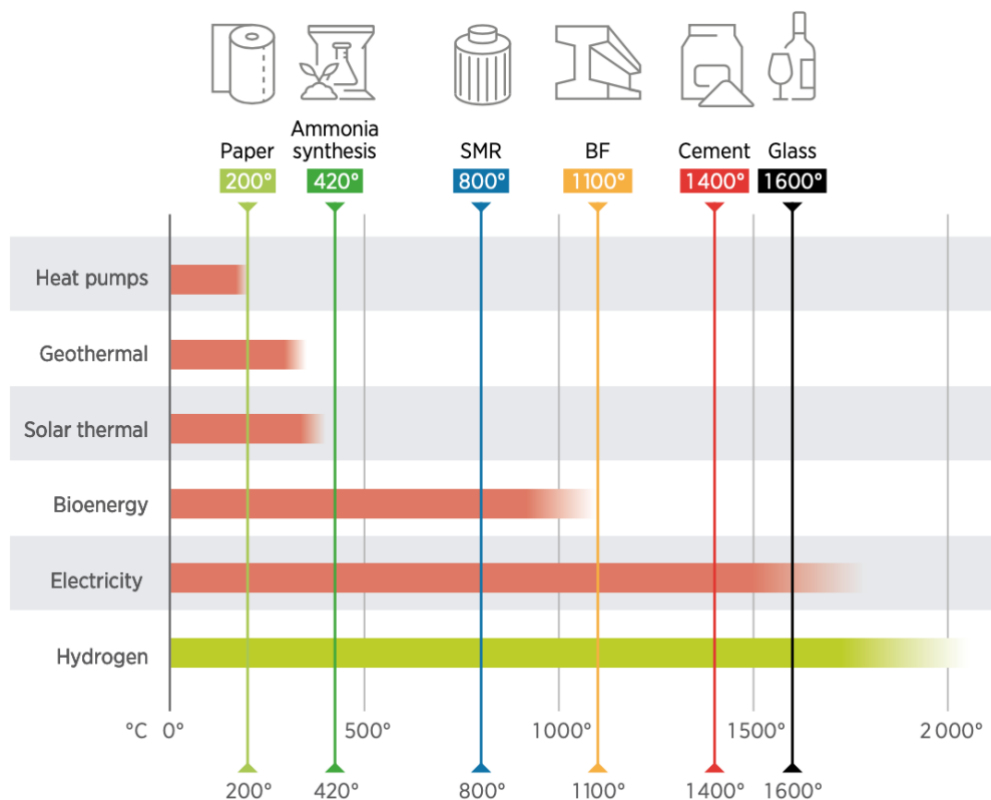


Figure 22: Working temperatures for selected renewable heat technologies and temperature requirements of selected industries [4].

In addition to everything mentioned above, the blending of hydrogen and natural gas to industrial activities can also be a way to start decarbonizing the industry sector. To make this possible, factories and industrial infrastructures must have local hydrogen production technologies close to the consumption point or an efficient transport mode for the hydrogen from the production point to the site of use. This can help reduce the emissions associated to industrial processes and boost the decarbonization of the industry sector.

However, this blending of hydrogen and natural gas to industrial activities must be analyzed according to the type of industry and the equipment and machinery in question. The reason for this is the fact that the equipment manufactured to operate with natural gas, do not work the same way with hydrogen, as it has different characteristics and properties.

For each type of equipment, it is necessary to assess how they are capable of operating with hydrogen blended in natural gas, for equipment already in new equipment that may be installed.

### **TURBINES:**

For already installed machines, the percentages of hydrogen, in volume, that can be blended without harming the equipment are shown in Table 5.

Table 5: Blending percentages, in volume, and adaptations required for turbines in operation [31,32].

|                                     | 0 – 10 %          | 10 - 30 %                    | 30 - 100 %                                                                     |
|-------------------------------------|-------------------|------------------------------|--------------------------------------------------------------------------------|
| Machines already installed, running | No changes needed | Changes or tweaks are needed | More profound changes, such as replacement of the combustion chamber or system |

For new machines:

- Depending on the manufacturer and the type and class of turbine, the maximum limits for new, ready-to-install turbines range from 20 to 100% of hydrogen in volume [31].

In Figure 23 and Figure 24, are presented the portfolios of two different brands that already manufacture hydrogen turbines.

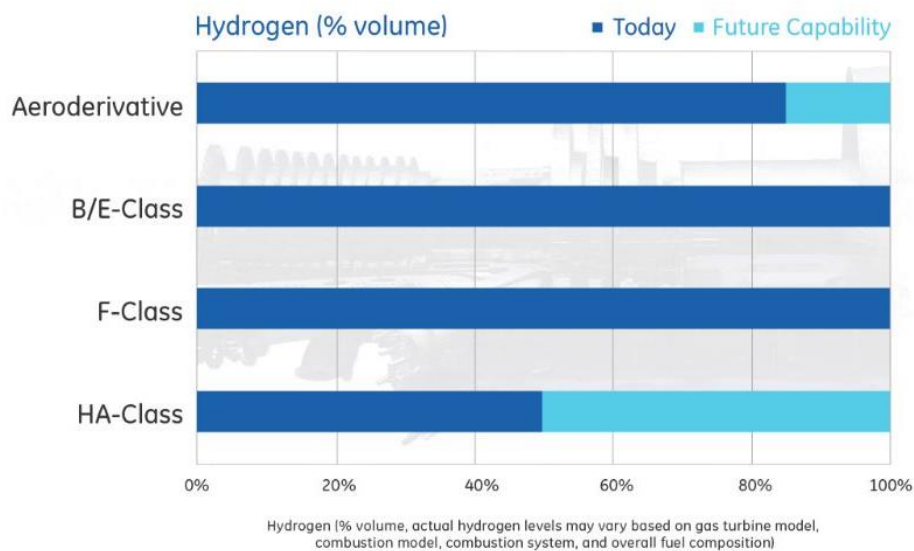


Figure 23: H<sub>2</sub> blending capability of various GE turbine models [33].

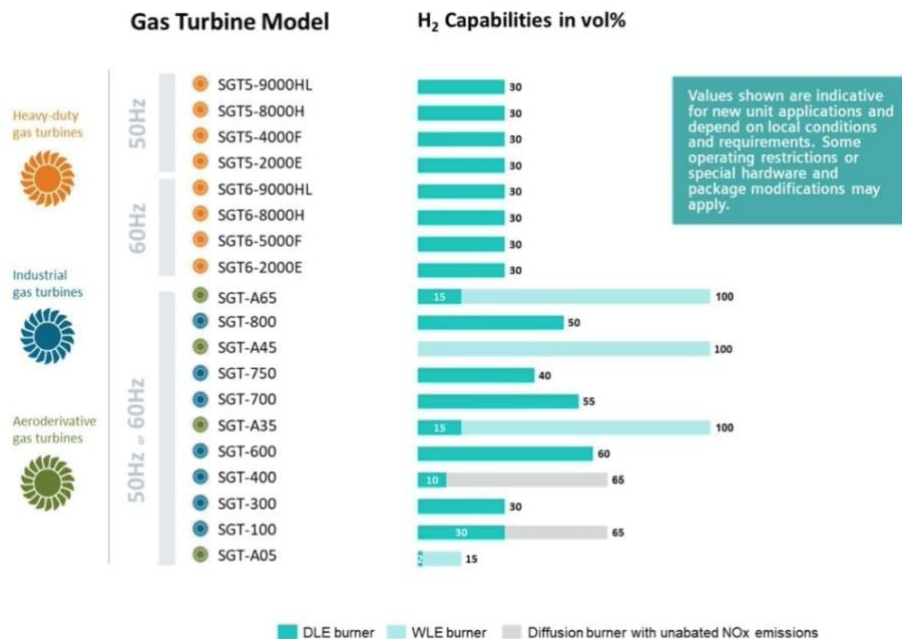


Figure 24: H<sub>2</sub> blending capability of various Siemens turbine models [34].

## BOILERS / BURNERS

For already installed machines, the percentages of hydrogen, in volume, that can be blended without harming the equipment are shown in Table 6.

Table 6: Blending percentages, in volume, and adaptations required for boilers/burners in operation [32].

|                                     | < 10 %               | Until 20 %                                       |
|-------------------------------------|----------------------|--------------------------------------------------|
| Machines already installed, running | No problems expected | Modifications or other measures may be necessary |

For new machines:

- Varies from manufacturer to manufacturer but have already been developed models capable of burning and operating on 100% hydrogen.

In Figure 25 are presented some hydrogen boilers manufactures.



Figure 25: Hydrogen boilers manufactures.

### 2.5.3. Blending in the gas grid

Blending is considered a transitory solution and consists of the injection of hydrogen from renewable sources into the gas grid, up to certain levels depending on several factors and components. This creates a mix of hydrogen and natural gas and as the share of hydrogen increases, the emissions associated with the usage of this source are reduced [2].

Furthermore, in the short term, the injection of hydrogen from renewable power into the gas grid represents a potential upside revenue to improve power-to-hydrogen's economics, enabling the continued operation of the electrolyser even if the hydrogen offtakers do not consume hydrogen at certain periods. In the long term, it holds the promise of storing large amounts of renewable power, while decarbonizing demand for natural gas [2]. Blending hydrogen in gas networks can also support initial deployment of low-carbon hydrogen and trigger cost reductions for low-carbon hydrogen production technologies [9].

Hydrogen can be injected into gas networks either directly in its pure form or as “premix” with natural gas, and for relatively low blending hydrogen rates, no major investments or changes in infrastructure are required [9]. Optimal blending concentrations strongly depend on the characteristics of the existing network, natural gas composition and end-use applications. Existing studies show that, generally, at relatively low hydrogen concentrations (up to 10% in volume), blending may not require major investment or modification to the infrastructure and can be done in a safe manner [2][9]. The hydrogen tolerance of polymer-based distribution networks is typically greater, potentially allowing blending of up to 20 % in volume of H<sub>2</sub> with minimal or possibly no modifications to the grid infrastructure [9].

As it can be seen in Figure 26, the injection of low-carbon hydrogen into gas grids has grown sevenfold since 2013, but volumes remain low. In 2020, approximately 3.5 kt H<sub>2</sub> were blended, almost all in Europe and mainly in Germany, which accounted for close to 60% of injected volumes [9].

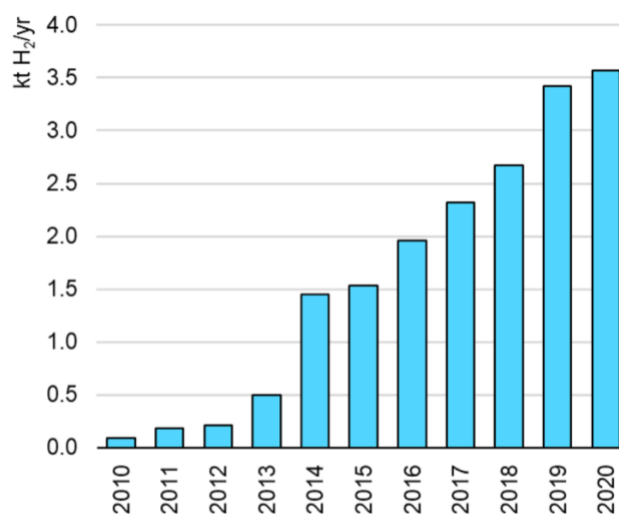


Figure 26: Estimated low-carbon hydrogen injected into gas networks, 2010-2020 [9].

However, blending still faces some technical and regulatory barriers related to natural gas quality which depending on the regulations in different countries can limit or completely prevent the injection of hydrogen into gas grids. Besides this, the hydrogen purity requirements of certain end users, including industrial clients, can further constrain blending. In addition, resulting changes in the physical characteristics of the gas can affect certain operations, such as metering [9]. Another challenge with blending is the fact that for higher concentrations of hydrogen, its chemical properties can cause embrittlement of steel pipelines and reactions between hydrogen and steel can create fissures in pipelines [9].

To sum up, in terms of climate change action, blending is a transitional solution that can help build up stable sources for low-carbon hydrogen demand until a dedicated hydrogen transport system is developed [9].

#### 2.5.4. Storage

Availability of hydrogen as an energy vector could enhance overall energy system flexibility by balancing short-term supply variability and meeting seasonal demand swings, thereby improving energy supply security. To fulfil this role, low-carbon hydrogen deployment will need to be coupled with development of cost-effective, large-scale, and long-term storage solutions [9].

In fact, the increased share of renewable sources within power systems intensifies the supply variability and intermittency. Therefore, energy storage is deemed as one of the solutions for stabilizing the supply of electricity to maintain generation-demand balance and to guarantee uninterrupted supply of energy to users [35].

Today hydrogen is most commonly stored as a gas or liquid in tanks for small-scale mobile and stationary applications. However, the smooth operation of large-scale and intercontinental hydrogen value chains in the future will require a much broader variety of storage options [7].

The most appropriate storage medium depends on the volume to be stored, the duration of storage, the required speed of discharge, and the geographic availability of different options. In general, however, geological storage is the best option for large-scale and long-term storage, while tanks are more suitable for short-term and small-scale storage [7].

This way, different end use applications for the stored hydrogen require different methods of storing it. For example, at an export terminal hydrogen storage may be required for a short period prior to shipping. Hours of hydrogen storage are needed at vehicle refueling stations, while days to weeks of storage would help users protect against potential mismatches in hydrogen supply and demand. Much longer-term and larger storage options would be required if hydrogen were used to bridge major seasonal changes in electricity supply or heat demand, or to provide system resilience [7].

Regarding long-term and large-scale storage, as mentioned above, geological storage is the most suitable alternative and salt caverns, depleted fields and aquifers are all possible options for this type of storage, being that salt caverns are a proven technology already used for many years in some industries while water aquifers is the least mature of the three geological storing options [9]. Some of these are currently used to store natural gas and provide significant economies of scale, high efficiency (the quantity of hydrogen injected divided by the quantity that can be extracted), low operational costs and low land costs. These characteristics mean that they are likely to be the lowest-cost option for hydrogen [7]. In Figure 27 are shown potential salt caverns locations across Europe, with their storage potential.

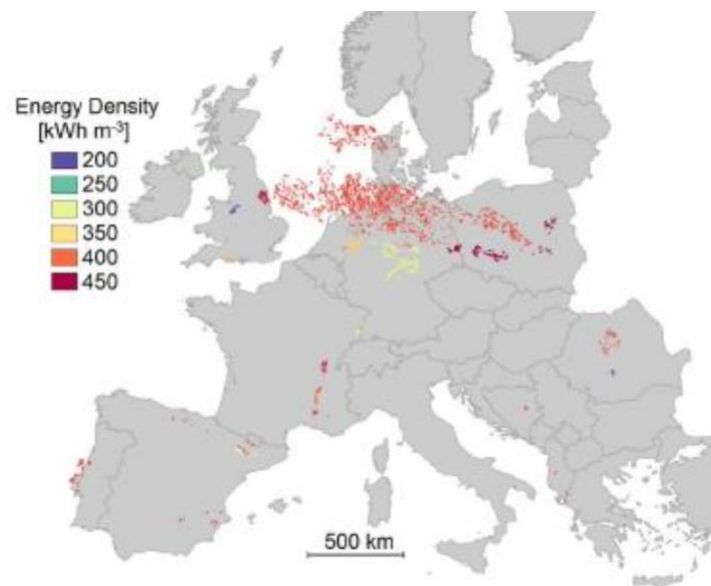


Figure 27: Distribution of potential salt caverns sites across Europe with their corresponding energy density [36].

Although geological storage offers the best prospects for long-term and large-scale storage, the geographical distribution, large size and minimum pressure requirements of sites make them much less suitable for short-term and smaller-scale storage [7].

In fact, for short-term and smaller-scale storage, storage tanks are the most suitable option. Tanks storing compressed or liquefied hydrogen have high discharge rates and efficiencies of around 99%, making them appropriate for smaller-scale applications where a local stock of fuel or feedstock needs to be readily available [7].

Research is continuing with the aim of finding ways to reduce the size of the tanks, which would be especially useful in densely populated areas. This includes looking at the scope for underground tanks that can tolerate 800 bar pressure and so enable greater compression of hydrogen. Hydrogen storage in solid-state materials such as metal and chemical hydrides is at an early stage of development but could potentially enable even greater densities of hydrogen to be stored at atmospheric pressure [7].

## 2.6 Hydrogen transportation

The total cost of hydrogen delivered to a specific location has two main components: production, already addressed at previous sections and transportation. The transport cost is mainly a function of two parameters: volume transported and distance, as shown in Figure 28 [37].

There are three ways of transporting hydrogen: via truck, pipeline or ship. For small volumes and short distances, trucks can be attractive, but as the volume increases, the density needs to be increased and trucks carrying liquid hydrogen need to be used. Further increases in volume or distance make pipelines the most cost-effective route, graduating from distribution pipelines (small diameter) to transmission pipelines as the volume increases. For very long distances or routes across water bodies, ships become the most attractive. Therefore, for most cross-border trade, trucks can be discarded since they are suited to smaller volumes [37].

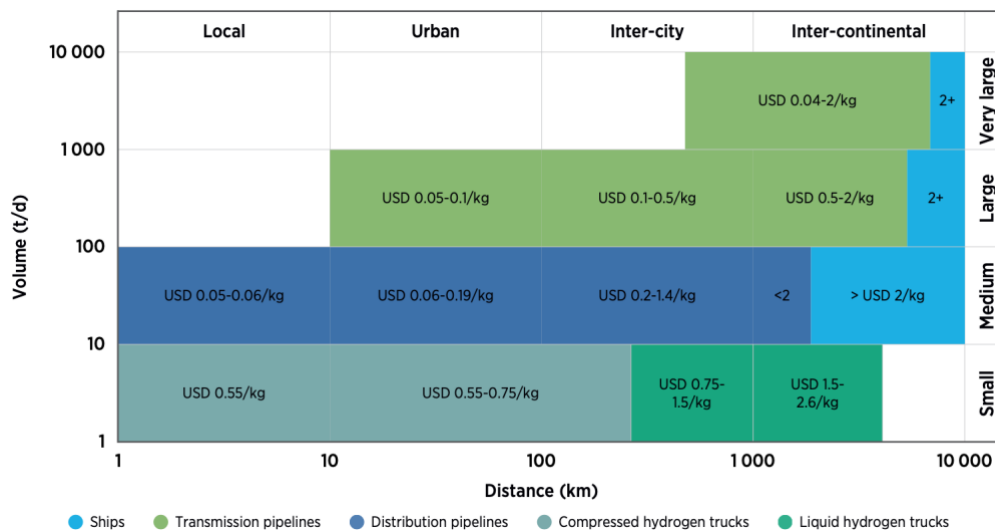


Figure 28: Hydrogen transport cost based on distance and volume [37].

Four hydrogen transportation technologies have the highest potential: pipelines that transport gaseous hydrogen; hydrogen transported as ammonia; liquefied hydrogen (LH<sub>2</sub>); and hydrogen stored in liquid organic hydrogen carriers (LOHC). The three non-pipeline technologies are known as hydrogen carriers [38]. Each of these non-gaseous pathways requires three steps: transforming gaseous hydrogen to the form and conditions suitable for transport; the transport step itself; and reconverting the carrier to pure gaseous hydrogen under the required conditions [37].

### PIPELINE (GASEOUS H<sub>2</sub>):

Gaseous hydrogen can be transported in pipelines, like natural gas. Before injection, the hydrogen is mechanically compressed to the operating pressure of the pipeline, usually higher than the outlet pressure of electrolyzers. As with natural gas pipelines, a mature hydrogen pipeline system with transmission and distribution grids also

requires metering stations, control valves and gates to manage flows and ensure onward distribution to end users [38].

Instead of building new pipelines, existing natural gas pipelines can be repurposed to transport hydrogen. The injection of hydrogen into existing gas grids is also under discussion, with blends of up to 20% hydrogen currently being tested in pilot projects [38].

Table 7 presents some advantages and disadvantages of transporting gaseous hydrogen via pipeline.

*Table 7: Advantages and disadvantages of transporting hydrogen via pipeline [37,38].*

| Advantages                                                                                                                                                                                                                                                                                                                                                                  | Disadvantages                                                                                                                                                                                                                                                                                                                  |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"> <li>• Transport and storage are proven at a commercial scale;</li> <li>• Existing natural gas network can be repurposed to hydrogen;</li> <li>• Low operational costs and lifetime;</li> <li>• No conversion requires (only compression);</li> <li>• Carbon-free carrier;</li> <li>• More attractive as the volume increases.</li> </ul> | <ul style="list-style-type: none"> <li>• High initial costs of new pipelines;</li> <li>• Not all the pipeline materials are suitable for hydrogen;</li> <li>• Cost increases significantly for offshore pipelines;</li> <li>• Large volumes of hydrogen are also necessary to achieve acceptable utilization rates.</li> </ul> |

### **AMMONIA:**

Ammonia ( $\text{NH}_3$ ) is a bulk chemical that is normally synthesized from natural gas and mainly used as chemical feedstock. However, it can also serve as a clean hydrogen storage medium. The medium is produced by reacting hydrogen and nitrogen to synthesize liquid ammonia. The liquid ammonia can then be transported in refrigerated tanks. Once it reaches its destination, the ammonia is broken down into its components, nitrogen and hydrogen, through an endothermic cracking process. The resulting gas mixture is then purified, and the nitrogen removed and released back into the atmosphere [38].

Table 8 presents some advantages and disadvantages of transporting hydrogen with ammonia as a carrier.

Table 8: Advantages and disadvantages of ammonia as a hydrogen carrier [37,38].

| Advantages                                                                                                                                                                                                                                                                               | Disadvantages                                                                                                                                                                                                                                                                                                                                                                                                                                 |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"> <li>• Already produced in large scale and globally traded;</li> <li>• Low transport losses;</li> <li>• Contains more hydrogen by volume than any of the other carrier;</li> <li>• Carbon free carrier;</li> <li>• Can be easily liquified.</li> </ul> | <ul style="list-style-type: none"> <li>• High energy consumption for ammonia synthesis;</li> <li>• High energy consumption and temperature required for reconversion;</li> <li>• Might require further purification of the hydrogen produced;</li> <li>• Toxic and corrosive;</li> <li>• Due to the safety concerns, it is questionable whether authorities would permit the transportation and use of ammonia in populated areas.</li> </ul> |

### **LIQUEFIED HYDROGEN (LH<sub>2</sub>):**

The volumetric storage density of hydrogen can be significantly improved through liquefaction, that is, cooling it below its boiling point of -253°C. After liquefaction, LH<sub>2</sub> is stored in specially insulated and double-hulled tanks. This limits heat transfer from the environment and subsequent losses due to evaporation, as built-up gas (boil-off) has to be vented. Under these conditions, LH<sub>2</sub> is already being transported via specially designed trailer trucks today. At the destination, LH<sub>2</sub> is usually vaporized into its gaseous form before use [38].

Table 9 presents some advantages and disadvantages of transporting liquefied hydrogen:

Table 9: Advantages and disadvantages of liquefied hydrogen as a carrier [37,38].

| Advantages                                                                                                                                                                                                                                                                                                                                           | Disadvantages                                                                                                                                                                                                                                                                                                                                      |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"> <li>• Liquefaction is a relatively well-established technology at small scale;</li> <li>• Does not require complex reconversion and provides high purity hydrogen;</li> <li>• Easier transport at the importing terminal;</li> <li>• Low energy conversion to increase pressure of hydrogen delivered.</li> </ul> | <ul style="list-style-type: none"> <li>• High energy losses for liquefaction;</li> <li>• High equipment cost;</li> <li>• Currently available only on a small scale;</li> <li>• Storage, handling and transportation of LH<sub>2</sub> are more complex compared to the other carriers;</li> <li>• Boil-off during shipping and storage.</li> </ul> |

### **LIQUID ORGANIC HYDROGEN CARRIERS (LOHC):**

Liquid organic hydrogen carriers are easily transported chemical compounds that can be reversibly hydrogenated and dehydrogenated. The hydrogenation process involves chemically binding hydrogen to the liquid compound so that it can be transported at atmospheric pressure like many other oil-like substances. At the destination, the hydrogen is released via an endothermic (heat-requiring) dehydrogenation process. The dehydrogenated LOHC can then be transported back to the hydrogen source for reuse [38]. There are several organic carrier substances available, among which toluene, dibenzyltoluene and benzyltoluene (so-called heat transfer fluids) are the most common [38].

Table 10 presents some advantages and disadvantages of liquid organic hydrogen carriers:

*Table 10: Advantages and disadvantages of liquid organic hydrogen carriers [37,38].*

| <b>Advantages</b>                                                                                                                                                                               | <b>Disadvantages</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"><li>• Can be transported as oil is today, using existing infrastructure;</li><li>• Low capital costs for all steps;</li><li>• Can be easily stored.</li></ul> | <ul style="list-style-type: none"><li>• High energy consumptions for dehydrogenation;</li><li>• Requires high temperature heat for dehydrogenation;</li><li>• Further purification of the hydrogen produced is required;</li><li>• Hydrogen requires compression;</li><li>• Only 4-7% of the weigh of the carrier is hydrogen;</li><li>• No clear chemical compound is the most attractive;</li><li>• Carriers would probably contain fossil CO<sub>2</sub>.</li></ul> |

A comparison of the main characteristics of the different hydrogen carriers mentioned above is shown in Figure 29.

| Main characteristics               |                                                       | Ammonia                                                                                                                                          | Liquefied hydrogen                                                                                                                                                                     | LOHC (benzyltoluene)                                                                                                                                        |
|------------------------------------|-------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Storage density                    | Volum. [kg H <sub>2</sub> /m <sup>3</sup> of carrier] | 121.2 <sup>1</sup>                                                                                                                               | 70.8                                                                                                                                                                                   | 55.2                                                                                                                                                        |
|                                    | Gravim. [kg H <sub>2</sub> /t of carrier]             | 177.5 <sup>1</sup>                                                                                                                               | 1,000                                                                                                                                                                                  | 62.7                                                                                                                                                        |
| Energy needs                       | Conversion [MWh/t H <sub>2</sub> ]                    | 5.75                                                                                                                                             | 12.0                                                                                                                                                                                   | 0.5                                                                                                                                                         |
|                                    | Reconversion [MWh/t H <sub>2</sub> ]                  | 11.2                                                                                                                                             | 0.6                                                                                                                                                                                    | 15.0                                                                                                                                                        |
| Technological and process maturity | Conversion – Small scale                              | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
|                                    | Conversion – Large scale                              | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
|                                    | Storage                                               | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
|                                    | Transportation – Ship                                 | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
|                                    | Transportation – Rail                                 | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
|                                    | Transportation – Truck                                | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
|                                    | Reconversion                                          | <div><div></div><div></div><div></div></div>                                                                                                     | <div><div></div><div></div><div></div></div>                                                                                                                                           | <div><div></div><div></div><div></div></div>                                                                                                                |
| Operational value propositions     | Advantages                                            | <ul style="list-style-type: none"> <li>• High storage capacity</li> <li>• Mature value chain, except for cracking process</li> </ul>             | <ul style="list-style-type: none"> <li>• No reconversion required</li> <li>• High purity hydrogen</li> </ul>                                                                           | <ul style="list-style-type: none"> <li>• Easy to store and transport (diesel-like liquid)</li> <li>• Use of existing infrastructure</li> </ul>              |
|                                    | Disadvantages                                         | <ul style="list-style-type: none"> <li>• Additional purification step needed</li> <li>• High energy requirements for cracking process</li> </ul> | <ul style="list-style-type: none"> <li>• Boil-off losses along value chain</li> <li>• High energy requirements for liquefaction</li> <li>• Storage and transport complexity</li> </ul> | <ul style="list-style-type: none"> <li>• Number of cycles impact environmental footprint</li> <li>• High energy requirements for dehydrogenation</li> </ul> |
|                                    | Safety                                                | <ul style="list-style-type: none"> <li>• Acute toxicity, flammable, explosive under heat, toxic to aquatic life</li> </ul>                       | <ul style="list-style-type: none"> <li>• Highly flammable with no visible flame, can form explosive mixtures with air</li> </ul>                                                       | <ul style="list-style-type: none"> <li>• Low toxicity, non-explosive, hazardous to aquatic environment</li> </ul>                                           |

Proven & commercial
  Prototype demonstrated
  Technology validated or under development



### 3. Case study definition

In this section, the project that led to the writing of this dissertation will be presented and explained as well as the main objectives and steps required to implement it.

This project, as explained in the previous chapters of this thesis, sits on the need for companies and industries to decarbonize their processes and activities, in order to reduce emissions with the ultimate objective of reaching carbon neutrality. This, as mentioned before can be achieved by using low carbon energy sources.

This way, the aim of this project is to perform a techno-economic analysis to compare two different hydrogen production strategies, whereby the first consists in the installation of a decentralized local hydrogen production unit via electrolysis, for self-consumption on site, whereas the second focuses on the study of a centralized big hydrogen production system with transportation of the hydrogen to the end use location. The hydrogen produced would be blended in the industrial facility gas consumption.

#### 3.1 Amcor Flexibles PT

The industrial environment chosen to conduct this study was Amcor Flexibles PT, which is a company specialized in developing and producing responsible and sustainable packaging for food, beverages, pharmaceutical, medical, home and personal care products, and more [39].

Amcor Flexibles PT is part of the Amcor Group, logo shown in Figure 30, which is a brand with almost 160 years of history. Having started as a manufacturer of pulp paper and paperboard products, at that time named APM – Australian Paper Manufacturers, over the years this company diversified its field of activity, adding a range of diverse packaging interests to its traditional papermaking activities. In the 1980s the company changed its name from APM to Amcor Limited to reflect the company's much broader range of interest. In 2000, Amcor demerged its business printing papers to focus on global packaging, and since then they have been a global leader in packaging. Today, Amcor Group employs more than 46 000 employees, in more that 225 locations spread out by over 40 countries worldwide and generates approximately US\$ 13 billion in sales [39].

The current Amcor Flexibles PT facility, in Porto, was established in 1950 under the name SPLC – Sociedade Portuguesa La Cellophane and was a pioneer in the flexible packaging industry in Portugal. After being acquired years later, there was a period of technological modernization and the specialization of several packaging areas, which is seen as the key to the company's development. A wide range of operations, supported by solid investment programs has led the company to have a competitive position both in the domestic and foreign markets.

In 2010, the Amcor Group acquired the company, and its name was changed to Amcor Flexibles Portugal. The company has gradually put itself in a position to meet any need for flexible packaging. Currently, the machinery available includes extrusion, printing, laminating/complexing, cutting and bag making machines. The plant is also equipped with testing equipment to ensure quality in the final product.

The company has a big commitment to sustainability and environmental concern in their industrial processes. In addition to presenting high recycling rates for industrial waste and manufacturing a high percentage of recycle-ready products, they are also increasingly investing in energy from renewable sources as their renewable energy use grew 57% from 2020 to 2021 [40].



Figure 30: Amcor logotype [39].

### 3.2 Energy consumptions and equipment

The current energy consumptions of Amcor Flexibles PT are essential data to the techno-economic analysis that is going to be performed for the case study that is being defined. In fact, being aware of the amount of electricity and natural gas that Amcor's industrial processes consume and the respective prices they pay is fundamental to establish the comparisons needed and to choose the suitable methodology to conduct the case study.

Thereby, in Table 11 and Table 12 are represented Amcor's energy consumption for the years of 2020 and 2021, with the respective amount paid and prices.

Table 11: Natural gas consumptions and prices.

|                 | Energy [kWh] | Volume [Nm <sup>3</sup> ] | Value paid [€] | Price [€/MWh] |
|-----------------|--------------|---------------------------|----------------|---------------|
| <b>Jan/2020</b> | 2 176 470    | 182 648                   | 68 918         | 31,66         |
| <b>Feb/2020</b> | 2 201 852    | 182 759                   | 69 496         | 31,56         |
| <b>Mar/2020</b> | 2 337 728    | 196 935                   | 73 808         | 31,57         |
| <b>Apr/2020</b> | 2 140 773    | 179 909                   | 67 768         | 31,66         |
| <b>May/2020</b> | 2 171 779    | 184 357                   | 56 014         | 25,79         |
| <b>Jun/2020</b> | 2 080 664    | 174 929                   | 53 697         | 25,81         |

|                 |           |         |        |       |
|-----------------|-----------|---------|--------|-------|
| <b>Jul/2020</b> | 2 125 942 | 178 004 | 54 904 | 25,83 |
| <b>Aug/2020</b> | 2 101 162 | 177 946 | 53 451 | 25,44 |
| <b>Sep/2020</b> | 2 288 730 | 193 873 | 58 734 | 25,66 |
| <b>Oct/2020</b> | 2 435 423 | 208 061 | 62 349 | 25,60 |
| <b>Nov/2020</b> | 2 390 208 | 201 993 | 61 150 | 25,58 |
| <b>Dec/2020</b> | 1 994 557 | 169 321 | 51 610 | 25,88 |
| <b>Jan/2021</b> | 2 070 623 | 175 482 | 53 360 | 25,77 |
| <b>Feb/2021</b> | 1 933 307 | 162 399 | 49 733 | 25,72 |
| <b>Mar/2021</b> | 2 358 536 | 198 084 | 60 375 | 25,60 |
| <b>Apr/2021</b> | 2 161 462 | 182 201 | 55 479 | 25,67 |
| <b>May/2021</b> | 2 346 017 | 201 387 | 60 106 | 25,62 |
| <b>Jun/2021</b> | 2 033 075 | 174 053 | 52 386 | 25,77 |
| <b>Jul/2021</b> | 2 378 946 | 200 347 | 47 348 | 19,90 |
| <b>Aug/2021</b> | 1 592 358 | 134 248 | 31 983 | 20,09 |
| <b>Sep/2021</b> | 2 315 564 | 196 750 | 46 070 | 19,90 |
| <b>Oct/2021</b> | 2 348 508 | 198 833 | 46 575 | 19,83 |
| <b>Nov/2021</b> | 2 397 795 | 204 871 | 47 397 | 19,77 |
| <b>Dec/2021</b> | 2 184 513 | 185 363 | 43 572 | 19,95 |

Table 12: Electricity consumptions and prices.

|                 | <b>Energy [kWh]</b> | <b>Value paid [€]</b> | <b>Price [€/MWh]</b> |
|-----------------|---------------------|-----------------------|----------------------|
| <b>Jan/2020</b> | 1 152 615           | 119 200,12            | 103,42               |
| <b>Feb/2020</b> | 1 115 407           | 115 766,90            | 103,79               |
| <b>Mar/2020</b> | 1 198 165           | 125 287,18            | 104,57               |
| <b>Apr/2020</b> | 1 105 642           | 117 280,96            | 106,07               |
| <b>May/2020</b> | 1 138 021           | 119 581,16            | 105,08               |
| <b>Jun/2020</b> | 1 067 146           | 111 067,76            | 104,08               |
| <b>Jul/2020</b> | 1 201 170           | 127 414,81            | 106,08               |
| <b>Aug/2020</b> | 1 105 000           | 124 105,70            | 112,31               |
| <b>Sep/2020</b> | 1 175 254           | 125 772,72            | 107,02               |
| <b>Oct/2020</b> | 1 202 408           | 127 791,09            | 106,28               |
| <b>Nov/2020</b> | 1 113 519           | 120 336,96            | 108,07               |
| <b>Dec/2020</b> | 937 680             | 100 043,46            | 106,69               |
| <b>Jan/2021</b> | 981 743             | 99 344,05             | 101,19               |
| <b>Feb/2021</b> | 952 943             | 96 091,16             | 100,84               |
| <b>Mar/2021</b> | 1 136 756           | 113 996,37            | 100,28               |

|                 |           |            |        |
|-----------------|-----------|------------|--------|
| <b>Apr/2021</b> | 982 531   | 97 357,54  | 99,09  |
| <b>May/2021</b> | 1 111 759 | 109 035,99 | 98,08  |
| <b>Jun/2021</b> | 1 013 607 | 98 506,85  | 97,18  |
| <b>Jul/2021</b> | 1 242 169 | 121 632,90 | 97,92  |
| <b>Aug/2021</b> | 771 228   | 75 401,50  | 97,77  |
| <b>Sep/2021</b> | 1 228 057 | 116 743,11 | 95,06  |
| <b>Oct/2021</b> | 1 197 650 | 113 125,91 | 94,46  |
| <b>Nov/2021</b> | 1 152 320 | 113 242,22 | 98,27  |
| <b>Dec/2021</b> | 1 022 446 | 113 242,22 | 110,76 |

It is also important to know the type of equipment installed in Amcor's industrial infrastructures, to ensure they work properly once the case study is put into practice and hydrogen blended with natural gas and injected in these machines.

This way, considering the different variants and specifications of the case study in question, the equipment from Amcor's facilities whose operation mode and characteristics must be taken into account are just the boilers and the respective burners.

Thus, there are four industrial boilers and burners to consider, whose characteristics are presented in Table 13 and Table 14 respectively.

*Table 13: Boiler's specifications.*

|                               | <b>Boiler 1</b> | <b>Boiler 2</b> | <b>Boiler 3</b> | <b>Boiler 4</b> |
|-------------------------------|-----------------|-----------------|-----------------|-----------------|
| <b>Manufacturer</b>           | CSC             | CSC             | CSC             | CSC             |
| <b>Model</b>                  | LM 12           | LM 12           | LM 300 T        | LM 300 T        |
| <b>Average power [kW]</b>     | 1395            | 1395            | 3500            | 3500            |
| <b>Heating fluid</b>          | Thermofluid     |                 |                 |                 |
| <b>Fluid temperature [°C]</b> | 260             | 260             | 280             | 280             |
| <b>Fuel</b>                   | Natural gas     |                 |                 |                 |

Table 14: Burner's specifications.

|                     | <b>Burner 1</b> | <b>Burner 2</b> | <b>Burner 3</b> | <b>Burner 4</b> |
|---------------------|-----------------|-----------------|-----------------|-----------------|
| <b>Manufacturer</b> | Weishaupt       | Weishaupt       | Weishaupt       | Weishaupt       |
| <b>Model</b>        | G7/1-D          | G7/1-D          | RGMS11/1-D      | G10/1-D         |
| <b>Power [kW]</b>   | 4,07            | 4,07            | 14,56           | 11,17           |

### 3.3 Potential decarbonization actions

This project has two different focuses of study, both connected between them but with different approaches to the introduction of hydrogen production to Amcor industrial activities.

The first approach consists in a decentralized hydrogen production, in Amcor's facilities, to produce hydrogen to blend in their gas grid. Different blend percentages were studied, with values that would require no changes or only slight adaptations of their equipment and infrastructures.

The other approach under analysis consists in a large-scale centralized hydrogen production, in a hypothetical location, and involves the transportation of the hydrogen to Amcor's installations considering the respective costs.

Thus, the two different approaches under assessment are presented and explained in Table 15.

Each one of these different approaches to hydrogen production study what could be viewed as a temporal evolution of the introduction of hydrogen in an industry, with a less disruptive phase (5% and 10% of hydrogen), that promotes the integration of hydrogen production technologies in an industrial environment, and which can be seen as a transition phase, as it involves zero or little infrastructure adaptation. On the other hand, a more transformational phase (15% and 20% hydrogen) already involves bigger investment and costs as a few adaptations and changes are needed to do in some equipment.

In this modeling work, the construction and installation options of water electrolyzers and all the components needed to ensure the safe and efficient production of hydrogen will be discussed and the most suitable configuration for each case will be determined. Therefore, this study will be based on a technical and technological analysis to ascertain the best components and technologies for the desired industrial process and the working conditions, combined with an economic analysis of the prices and tariffs associated with the hydrogen production and all the components required

for it, to ensure that the final solutions selected guarantee an efficient production of hydrogen, at the best price possible.

*Table 15: Potential decarbonization actions.*

|                                     | <b>Description</b>                                                                                                                                        | <b>%H2 vol<br/>under study</b> | <b>Time frame</b>    |
|-------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------------|----------------------|
| <b>Decentralized<br/>production</b> | Hydrogen produced locally, in a small-scale process, to supply Amcor's industrial activities, by blending it into their gas grid, in reduced percentages. | 5%<br>10%<br>15%<br>20%        | Short/medium<br>term |
| <b>Centralized<br/>production</b>   | Hydrogen produced in a large-scale production facility and transported to Amcor to supply the industrial processes, by injecting it into their equipment. | 5%<br>10%<br>15%<br>20%        | Long term            |



## 4. Methodological approach

After defining the case study of this dissertation and having provided a contextualization of the problem under study and the main factors that influence it, in this section the methodology followed and applied during this study is explained. This way, all the steps taken and analysis done to go from the definition of the case study to the achievement of results are described in the next pages.

Thus, this section consists of a techno-economic analysis of different percentages of hydrogen blended in Amcor's natural gas grid.

The methodology proposed in this work is then divided in 3 main parts: a technical analysis framework, where all the technical aspects of the project will be described and explained in detail, an economic analysis framework, composed by an explanation of all the steps taken to perform the economic analysis of the project and lastly a section for the data input required to perform the study. In this part, the properties of the gases in play will be reviewed, and the electrolyser and economic inputs will be presented and explained.

### 4.1 Technical analysis framework

In the technical analysis, the objective is to determine, for a given hydrogen blending ratio, the required electrolyser capacity to produce the necessary amount of hydrogen to meet Amcor's needs for its industrial processes as well as the amount of hydrogen produced by the electrolyser hourly for an effective sizing of the technology to install.

The blending ratio is the percentage, in volume, of hydrogen blended with natural gas. This value will change according to the project phase under analysis and is given by the following expression:

$$BR = \frac{V_{H_2}}{V_{blend}} \times 100 \text{ [%]} \quad (1)$$

Where  $V_{H_2}$  is the volume of hydrogen (Nm<sup>3</sup>) and  $V_{blend}$  represents the total blend volume (Nm<sup>3</sup>).

For a given blending ratio, it is necessary to determine the high heating value (HHV) of the blended gas, and this property can be calculated as shown by expression (2).

$$HHV_{blend} = HHV_{NG} \times \frac{100 - BR}{100} + HHV_{H_2} \times \frac{BR}{100} \text{ [MJ/ Nm}^3\text{]} \quad (2)$$

In order to supply the same energy demand to the final users, an energy balance related to the specific H<sub>2</sub>/NG blend gas mixture must be performed [41]. So, considering the HHV of the blended gas, the volume of the blended gas and the hydrogen volume demand are calculated as demonstrated in equations (3) and (4) respectively:

$$V_{blend}(i) = \frac{E_{gas}(i)}{HHV_{blend}} \times 3,6 \times 10^6 \text{ [Nm}^3\text{]} \quad (3)$$

$$V_{H_2}(i) = V_{blend}(i) \times \frac{BR}{100} \text{ [Nm}^3\text{]} \quad (4)$$

Where  $E_{gas}$  is the hourly energy demand (GWh) (input from real gas demand data),  $HHV_{blend}$  is the blend higher heating value, and their quotient is multiplied by a conversion coefficient from GWh to MJ.

Having the hydrogen volume demand, the next step was to determine the corresponding mass, in kg, using the hydrogen density through the expression demonstrated in equation (5).

$$m_{H_2}(i) = V_{H_2}(i) \times \rho_{H_2} \text{ [kg]} \quad (5)$$

As the available information on natural gas demand data is only per month, all the parameters were calculated referring to monthly values. Without any other information. It was necessary to assume that the consumption of natural gas was the same in each hour of each month, and as such it was necessary to divide the monthly result obtained by the number of hours of each month, so that the hourly hydrogen needs could be used to estimate the required electrolyser size.

With the hourly hydrogen demand already calculated, the next step was to calculate the size (MW) needed for the electrolyser. As is known that a 1MW electrolyser is capable of producing approximately 18kg of hydrogen per hour, to calculate the maximum power required, it is necessary to divide the hydrogen production, in kg/h, by 18, as shown in equation (6).

$$Max \text{ required power} = \frac{Prod}{18} \text{ [MW]} \quad (6)$$

To ensure that the electrolyser power is enough to produce the amount of hydrogen needed, a safety coefficient of 20% was applied to the maximum power required, effectively enabling a slight oversizing of the equipment.

Additionally, it is also necessary to determine the amount of electricity and water necessary to feed to the electrolysis process. This way, knowing that for each kg of hydrogen it is necessary to supply 10L of water to the process [42], to calculate the total amount of water needed, the total mass of hydrogen to produce was determined and this value was multiplied by 10.

Regarding the electricity necessary, and having the value of the electrolyser efficiency,  $\eta_{el,kWh/kg_{H_2}}$ , the electricity demand can be determined by multiplying this value by the total amount of hydrogen needed to produce,  $m_{H_2}$ , kg.

## 4.2 Economic analysis framework

In the economic analysis, the main objective was to assess all the costs related to the process, as well as the sources of revenue, or in this case savings, arising from it. This study had as its final objective, understanding the price at which it would be possible to produce hydrogen to supply Amcor's industrial activities and to assess whether this alternative could be viable for implementation. This section describes the calculations used in the economic analysis, while the following section provides all the inputs used.

The first was to understand the investment that has to be made in equipment and infrastructures to be able to meet Amcor's production needs, depending on the blending ration considered. In other words, the electrolyser CAPEX had to be determined and, this was done by determining the technology to install and the size of electrolyser needed, determined in the technical analysis.

Having determined the investment needed, the depreciation of equipment was also considered in the economic model, bearing in mind the degradation and lifespan of each component.

After having the capital expenses determined, the operational costs of the project were analyzed. Thereby, the expenses regarding the water and electricity supply to the electrolyser, taking into account the respective prices and amounts consumed, as well as the costs with O&M (operation and maintenance) of the equipment were calculated for each case study. These values were introduced in the economic model as annual expenses.

With all the capital and operational expenses determined, the next step was to calculate the levelized cost of hydrogen (LCOH), which is the average revenue per kg of hydrogen produced that would be required to recover the construction and operating costs of the generating facility over a given financial lifetime and duty cycle. This methodology is used to account for all the capital and operating costs of producing

hydrogen, and therefore enables different production routes to be compared on a similar basis.

The LCOH is calculated by expression (7), presented below.

$$LCOH = \frac{I_0 + \sum_{t=1}^n \frac{I_t + E_t + M_t}{(1+r)^t}}{\sum_{t=1}^n \frac{H_t}{(1+r)^t}} \quad [€/kg] \quad (7)$$

- $I_0$  – Investment expenditure in year 0;
- $I_t$  – Investment expenditure in year  $t$  (stack replacement costs);
- $E_t$  – Electricity costs in year  $t$ ;
- $M_t$  – Other operational expenditures in year  $t$ ;
- $H_t$  – Hydrogen production in year  $t$ ;
- $r$  – Discount rate;
- $n$  – Lifespan of the system.

The LCOH determined enables the planning of the investment, and allows the study of different hydrogen production scenarios, for example, by the variation of the price of electricity, so that they can later be compared with the process fueled only by natural gas. All the economic analysis described above was done for both decentralized and centralized production.

Additionally, for the centralized production case, the transportation costs were considered as well, which depend on the amount of hydrogen transported, the distance to cover and of course the transportation mode chosen. Thus, the most suitable option will be assessed and the viable limits for distance and volume of hydrogen to be transported will be studied and included in the economic model for the centralized production option.

For both decentralized and centralized production scenarios, for the cases of 15% and 20% blend ratios, as said before, some adaptations need to happen, and the cost associated with them must be considered. These costs, were considered as part the investment required for the project, being included in the CAPEX.

To carry out the economic analysis, a financial indicator used was the net present value, which indicates the current total value of a future stream of payments and, this way, allows to analyze the profitability of a projected investment or project. This ratio is given by equation (8).

$$NPV = \sum_{t=1}^n \frac{R_t}{(1+i)^t} \quad (8)$$

- $R_t$  – Net cash inflow-outflows during a single period  $t$ ;
- $i$  – Discount rate;
- $t$  – Number of timer periods.

## 4.3 Data inputs

### 4.3.1 Thermo-physical properties of blended gases

Firstly, a bibliographic study was conducted in order to understand the main hydrogen and natural gas properties needed to correctly perform the calculations required for the study. Thus, in Table 16, represented below, the main characteristics of both natural gas and hydrogen are presented.

*Table 16: Thermo-physical properties of blended gases [41,43,44].*

|                                               | Natural Gas | Hydrogen |
|-----------------------------------------------|-------------|----------|
| <b>Density [kg/ Nm<sup>3</sup>]</b>           | 0,8141      | 0,089    |
| <b>HHV [MJ/ Nm<sup>3</sup>]</b>               | 42,48       | 12,7     |
| <b>Wobbe Index range [MJ/ Nm<sup>3</sup>]</b> | 53,53       | 46       |

The natural gas composition is not exactly the same everywhere and may have slight variations in the percentages of components depending on the origin of the gas, so and because the company in study is located in Portugal, the properties displayed above were withdrawn from the technical reports from REN, which is the company responsible for the energy networks in Portugal, and some other gas distributors.

### 4.3.2 Electrolyser

Firstly, it is required to decide the technology of the electrolyser to install and, as described in section 2.3 of this dissertation, there are a few different technologies to produce hydrogen by electrolysis. However, the most mature and commercially available are alkaline and PEM electrolysers, so the choice of the technology to install was between one of these two, considering the characteristics of the installation and process.

As this project was developed considering the use of grid electricity, this allows the electrolyser to operate at a high and constant load factor, equaling their availability once annual maintenance has been taken into account, known as base load functioning. Thus, for this type of operation, running on grid electricity, alkaline

electrolysers are the most suitable technology, as PEM are more appropriate when operating following variable renewable sources.

A hydrogen production unit by electrolysis has multiple components, from the electrolyser itself, to all the support equipment and infrastructure. For an alkaline technology these elements are displayed in Figure 31 and explained below.

- 1- **Central water purification system** – Converts tap water into clean deionized water, suitable for cell stacks.
- 2- **DC rectifiers / transformers** – Converts AC input to DC power for electrolyzers and ancillary equipment components.
- 3- **Electrical substation** – Transformer and switchgear where high voltage from the grid is converted to medium voltage AC.
- 4- **Cell stacks** – Generate hydrogen and oxygen from water.
- 5- **Option hydrogen purification system** – Hydrogen can be further purified to fuel cell quality (99.998%).
- 6- **Central cooling system** – Cools water circulating through the cell stacks to optimize electrolysis efficiency.
- 7- **Control room** – Provides user interface to control and monitor the unit.

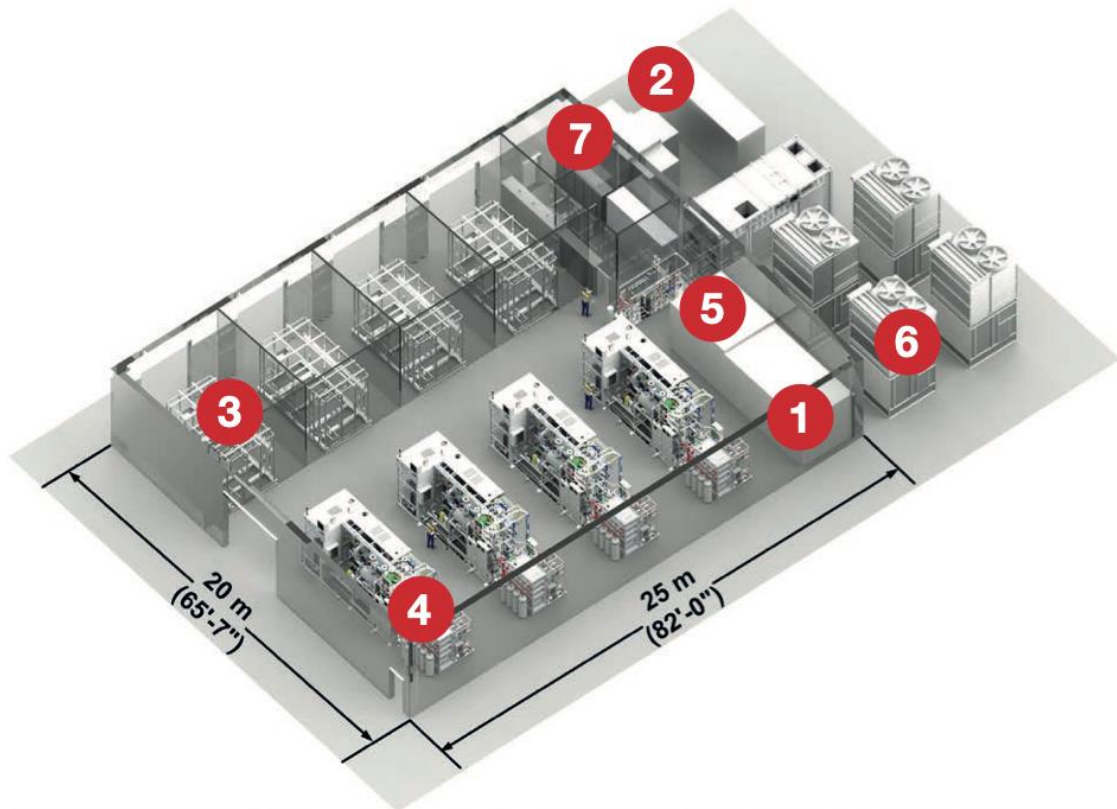


Figure 31: Alkaline electrolyser components [45].

With the electrolyser technology already decided, to correctly conduct the study, it is necessary to define some electrolyser parameters that will be needed to perform both the technical and economic analysis.

Firstly, it was necessary to estimate the investment required for the hydrogen production unit – CAPEX. This value aggregates the electrolyser costs at system/plant level, including all balance of plant and auxiliary systems, also including an additional quota for all other direct costs such as engineering, construction and installation.

Regarding the decentralized production case, to reach an acceptable CAPEX value for an alkaline electrolyser, two different sources were taken into account and their average value was considered, as demonstrated in Table 17.

Table 17: Alkaline electrolyser CAPEX.

|                       | CAPEX [€/kW] | Source |
|-----------------------|--------------|--------|
| Alkaline electrolyser | 800          | [46]   |
|                       | 880          | [47]   |
| Average               | 840          |        |

As in the decentralized scenario the hydrogen production is on a small scale, the CAPEX used was 840 €/kW.

However, the evolution of an electrolyser CAPEX tends to decrease as its size increases, as shown in Figure 32. In fact, as can be seen, CAPEX values on the order of 400 €/kW have been projected for alkaline systems, but this will require further upscaling up to 100 MW [48].

This way, for the centralized hydrogen production framework, as the electrolyser size was assumed to be 10MW, by analyzing the graph in Figure 32, the CAPEX considered for the calculations was 650 €/kW.

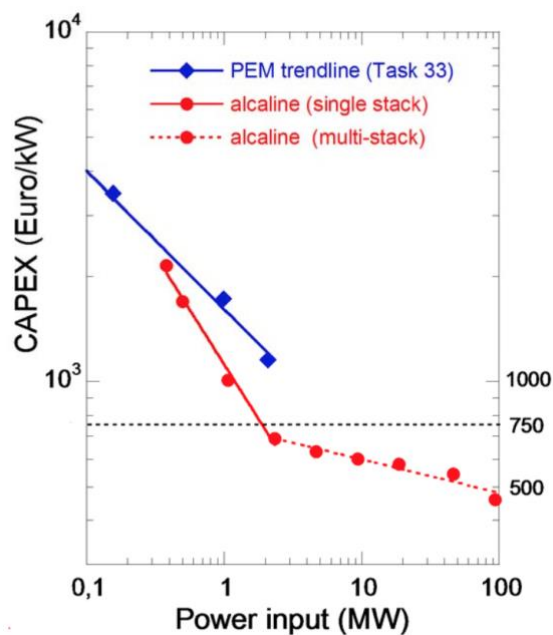


Figure 32: Electrolyser CAPEX as a function of the electrolyser size [48].

Another input data needed is the electrolyser efficiency, in kWh/kgH<sub>2</sub>, so that the electricity consumptions and costs can be determined. For an alkaline electrolyser, a common value to consider is 55 kWh/kgH<sub>2</sub> [49].

The total CAPEX of an electrolyser is composed of the system components (around 70%) and the stack itself (around 30%), typically needing to be replaced after 60 000 – 80 000 hours, introducing an additional CAPEX component related to stack replacement that depends on the operating hours of the electrolyser itself [41]. On the other hand, the system components of an alkaline electrolyser are annualized by considering a lifespan of 25 years lifetime [41]. Additionally, the yearly operation and maintenance (O&M) costs are added as a percentage of the upfront CAPEX.

Thereby, in Table 18, is presented a resume of these costs and the lifespan of different components of an alkaline electrolyser, EZ.

*Table 18: Some costs of alkaline electrolysers.*

|                 | <b>System</b> | <b>Stack</b>           | <b>O&amp;M</b>     |
|-----------------|---------------|------------------------|--------------------|
| <b>Costs</b>    | 70% EZ CAPEX  | 30% EZ CAPEX           | 2% EZ CAPEX / year |
| <b>Lifespan</b> | 25 years      | 60 – 80 thousand hours |                    |

The technical analysis described in section 4.1, explained all the methodology developed for the sizing of the electrolyser. All the intermediate calculations for the monthly values of the blend volume, hydrogen volume and mass and the hourly production are shown in the annexes.

### 4.3.3 Economic inputs

To perform the economic analysis of the project and determine all the costs and expenses related with the operation of the electrolyser some additional inputs are required.

First, it is necessary to define the discount ratio used, and for this type of projects, a discount rate of 5% is usually considered [41].

As mentioned in the previous section, the electrolyser system and stack have an estimated lifespan of 25 years and 60 to 80 thousand hours of operating time respectively. This way, assuming the installation will operate for 25 years, the depreciation of the equipment will occur during this period of time, with payments of equal amounts (percentage of the investment) during the equipment useful life.

For the system components, the initial investment, made in year 0 of the project, will be paid over the 25 years with equal amounts every year.

For the stack components, because of the shorter useful lifetime, a new investment will have to be made every 8 years for the two first investments while the third, and final one, was considered to last 9 years as it would not be realistic to make replacement so close to the end of the operating period. Additionally, this reflects potential improvements to the lifetime of the stacks over the lifetime of the electrolyzer. This way, investments in stacks were considered to be made in year 0, 9 and 17 of the project.

The operational costs of the electrolyser – OPEX – such as the water and electricity used in the electrolysis process and the O&M need to be considered as well.

The prices associated with these expenses, and which will serve as inputs to determine the total costs of the process are presented in Table 19.

*Table 19: OPEX costs.*

| Expense     | Costs                    |
|-------------|--------------------------|
| Water       | 1,8 [€/ m <sup>3</sup> ] |
| Electricity | 60 [€/MWh]               |
| Natural gas | 25,23 [€/MWh]            |

Regarding the water expenses, it was considered that, for each kilogram of hydrogen produced, it was necessary 10L of water [50].

Other expenses that need to be assessed are the costs involving Amcor's boilers/burners. As mentioned before, blend ratios of 15% and 20% required some changes and adaptations of the burners. With that said, and because there is not much information about the additional investment needed to adapt the burners to receive these quantities of hydrogen, and having available the Amcor's burners portfolio, it was assumed that the costs of adaptation were a 20% percentage of the costs of the burners. Following this logic, the additional expenses with these adaptations were 30 500€.

Lastly, after studying all the costs common to both the centralized and decentralized hydrogen production scenario, one other expense which must be considered but only to the centralized case is the hydrogen transportation from the production location to the end-use site.

The transportation of the hydrogen was assumed to occur by pipeline through relatively short distances (10 to 20 km), so that the results could be compared to the decentralized production, and conclusions withdrawn from the study. This reflects that there is not current hydrogen transportation and distribution infrastructure, which would then have to be built to enable a centralized production.

The assumed costs associated with transport are then presented in Table 20 and Table 21.

Table 20: Hydrogen transportation costs by pipeline [36].

|          |               | Costs [M€/km] |
|----------|---------------|---------------|
| Pipeline | New           | 2,2           |
|          | Repurposed NG | 0,4           |

Table 21: Amcor's costs with transportation, M€.

|          |               | Distance [km] |    |
|----------|---------------|---------------|----|
|          |               | 10            | 20 |
| Pipeline | New           | 22            | 44 |
|          | Repurposed NG | 4             | 8  |



## 5. Analysis of the results

In this section the results achieved by following the methodology described in chapter 4 will be presented, divided in the parts: the first one referring to the technical analysis of the substitution of natural gas with hydrogen, the second one focusing on production costs, for both decentralized and centralized production, and in the third one assessing the hydrogen competitiveness.

### 5.1 Technical analysis

Considering the HHV of each gas, Table 22 presents the values for the HHV of each of the blend ratio concentrations studied, with the respective volume of natural gas. As can be seen, the increased mixture of H<sub>2</sub> with natural gas reduces the HHV, which implies that to maintain the same energy use, the amount of volume of gas will have to increase. This could have implications on the existing infrastructure at Amcor, particularly in pipes or valves, that may not be prepared for such volumes of gas.

Table 22: HHV for the different blend ratios under study.

|                              | BR = 5%   | BR = 10%  | BR = 15%  | BR = 20%  |
|------------------------------|-----------|-----------|-----------|-----------|
| HHV [MJ/ Nm <sup>3</sup> ]   | 41,0      | 39,5      | 38        | 36,5      |
| NG volume [Nm <sup>3</sup> ] | 2 189 509 | 2 152 284 | 2 112 521 | 2 069 374 |

As one of the project objectives was to decrease Amcor's natural gas dependence and so, as expected, the results show that as the percentage of hydrogen in the blend increases, the natural gas demand decreases exponentially, as can be seen in the graph presented in Figure 33. This means that for the low levels of blending considered in this work (5% to 20%), the impact in reducing natural gas use would be small (between 1,5% and 7%).

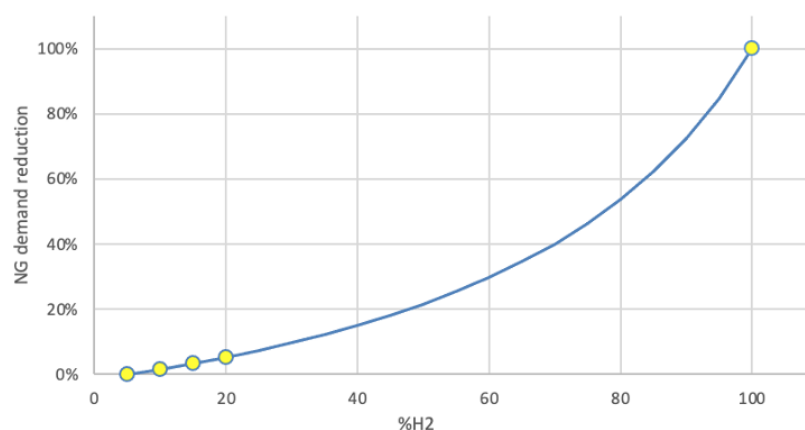


Figure 33: Reduction in the natural gas demand with the percentage of H<sub>2</sub>.

As Amcor's natural gas consumptions decrease with the introduction of hydrogen in their industrial processes' energy supply, this reduction is also associated with lower CO<sub>2</sub> emissions, that similarly with the gas natural demand, decrease exponentially, as seen in Figure 34.

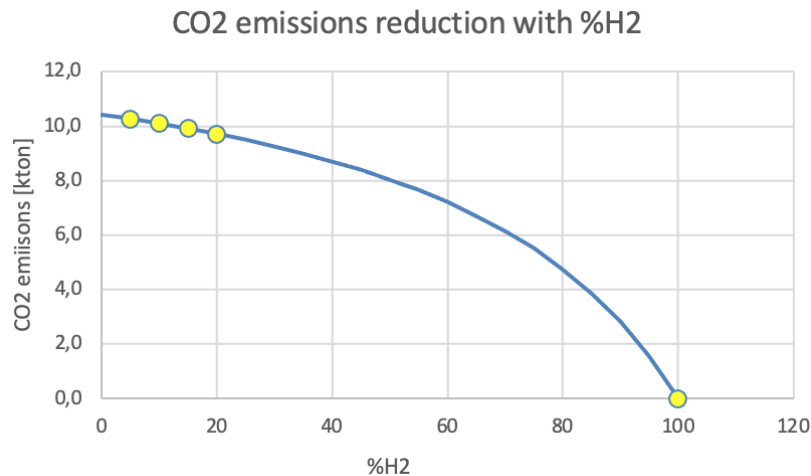


Figure 34: Carbon dioxide emissions reduction with the percentage of H<sub>2</sub>.

For each of the blend ratios studied, the total mass of hydrogen, in kg, required to produce to satisfy Amcor's demand is presented in Table 23.

Table 23: Hydrogen demand, in kg.

|                | H <sub>2</sub> demand [kg] |         |         |         |
|----------------|----------------------------|---------|---------|---------|
|                | BR=5%                      | BR=10%  | BR=15%  | BR=20%  |
| <b>2020</b>    | 10335,3                    | 21449,7 | 33434,9 | 46397,3 |
| <b>2021</b>    | 10208,4                    | 21186,5 | 33024,5 | 45827,8 |
| <b>Average</b> | 10271,9                    | 21318,1 | 33229,7 | 46112,5 |

Regarding operational parameters, and assuming that the blend ratio for each situation is constant every month, this means that hydrogen demand would not be the same every month, as it would follow the usage of natural gas. These variations in H<sub>2</sub> production are then presented in Figure 35, Figure 36, Figure 37 and Figure 38.

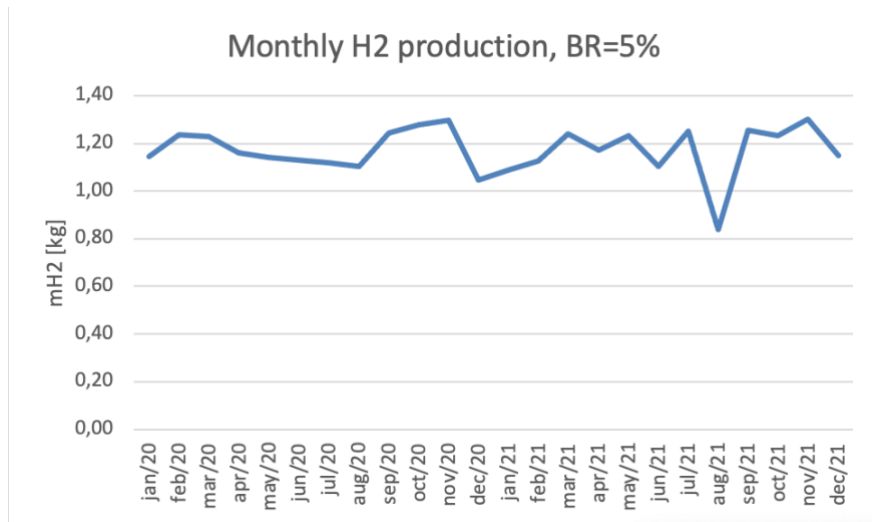


Figure 35: H2 monthly production, BR=5%.

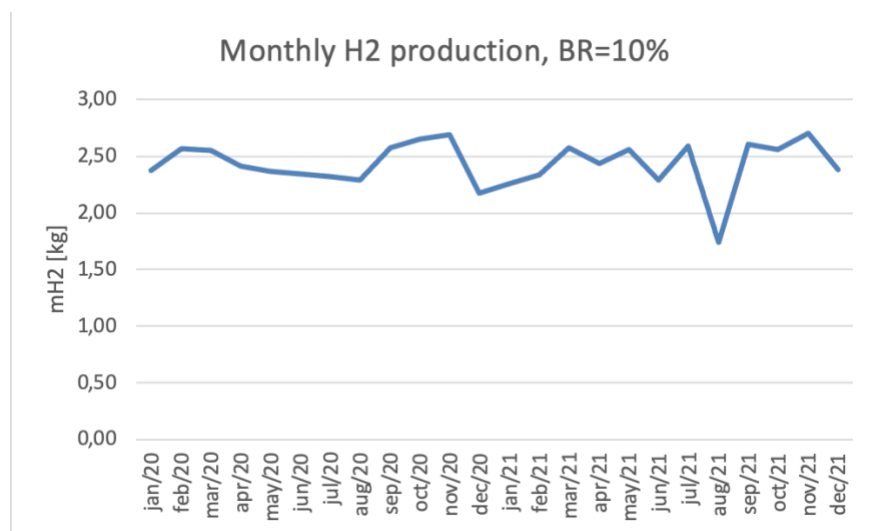


Figure 36: H2 monthly production, BR=10%.

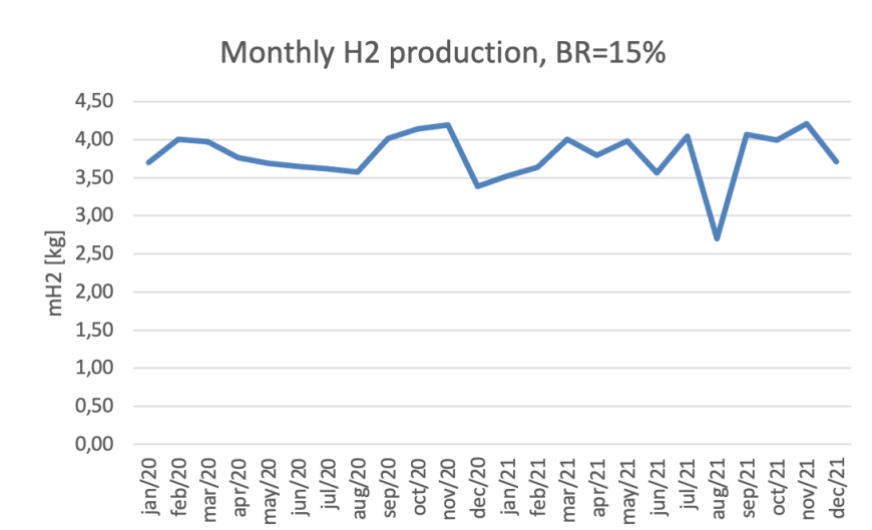


Figure 37: H2 monthly production, BR=15%.

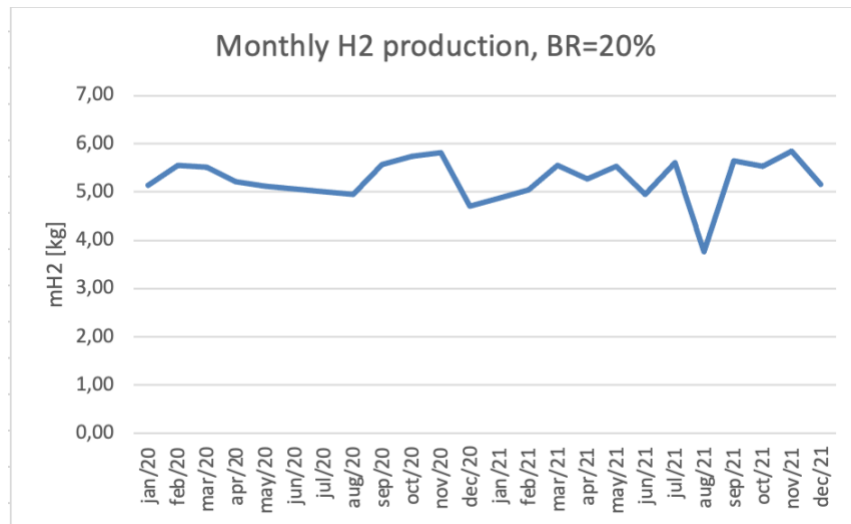


Figure 38: H2 monthly production, BR=20%.

Although for this study it was considered the blend ratio as always constant, by varying the production, it could also have been assumed that the monthly hydrogen production was always the same and the blend ratio varied accordingly. Thus, in Figure 39, Figure 40, Figure 41 and Figure 42 are presented the blend ratio variations for a constant hydrogen production, for each of the studied situations. However, this change in blending ratio could introduce some operational constraints, as some months have shown significant deviations of the average, which could require the fine tuning of the burners and other equipment to be able to efficiently operate with those levels of blending.

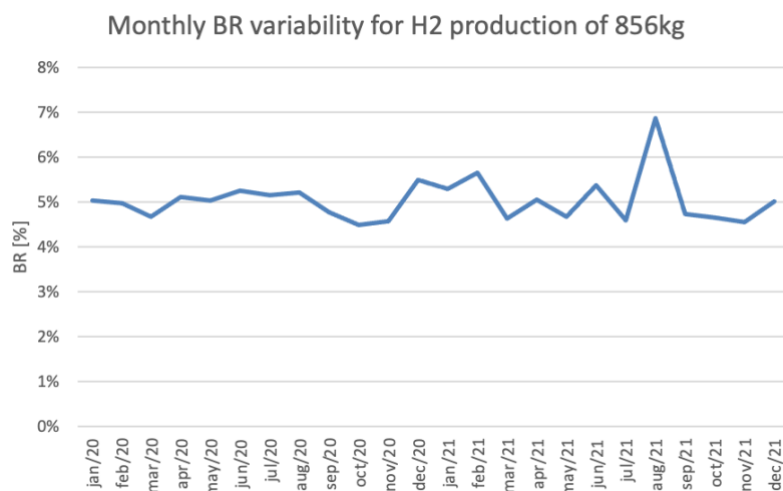


Figure 39: Monthly BR variation for H2 production of 856kg.

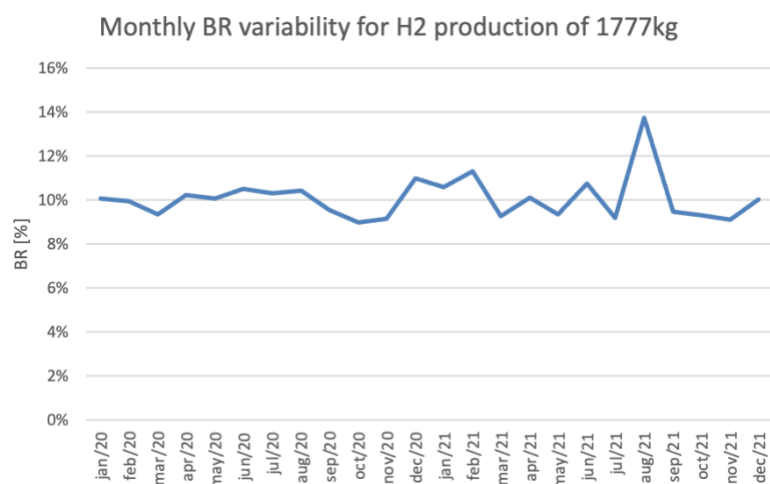


Figure 40: Monthly BR variation for H2 production of 1777kg.

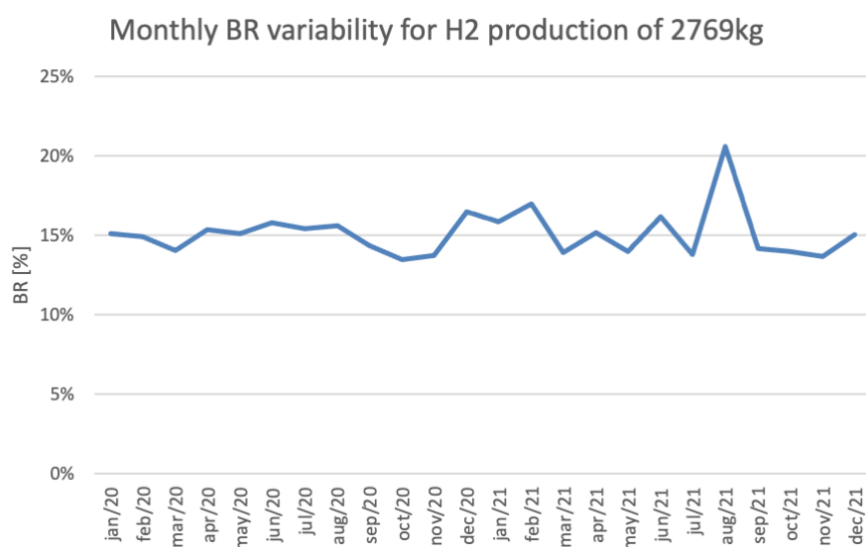


Figure 41: Monthly BR variation for H2 production of 2769kg.

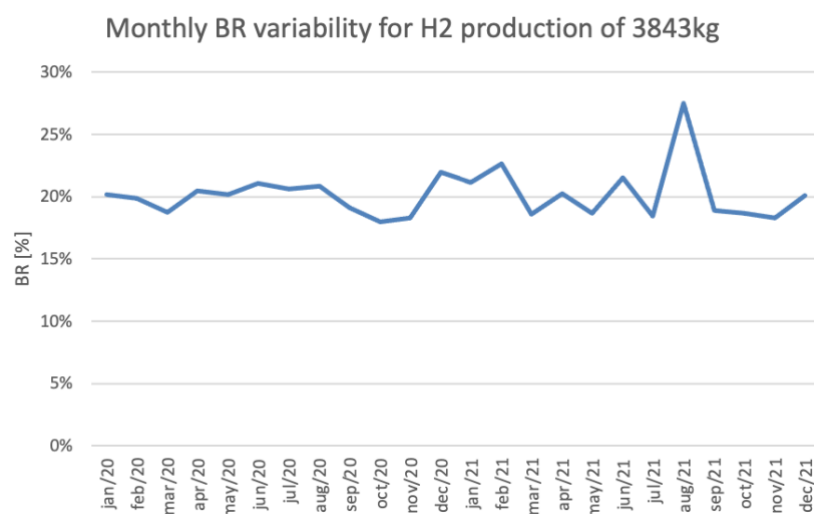


Figure 42: Monthly BR variation for H2 production of 3843kg.

Considering the volumes of hydrogen previously estimated, the electrolyser size, for the decentralized production scenario, for each of the different blend ratios are presented in Table 24. As can be seen, due to the small scale of the industrial facility, only small electrolysers would be required to supply the necessary hydrogen volumes. It is also relevant to keep in mind that the values exhibited in the table already include 20% safety coefficient mentioned in the technical analysis framework section.

*Table 24: Electrolyser size for the different blend ratios (decentralized production).*

|                               | <b>BR=5%</b> | <b>BR=10%</b> | <b>BR=15%</b> | <b>BR=20%</b> |
|-------------------------------|--------------|---------------|---------------|---------------|
| <b>Electrolyser size [MW]</b> | 0,1          | 0,2           | 0,3           | 0,4           |

Considering the required volumes of hydrogen and the estimated size of the electrolysers, it was also important to determine their load factor, which represents how much energy was used during a certain period, versus how much energy would have been used, if the power had been left on during a period of peak demand, in other words, is an indicator for describing the consumption characteristics of electricity over a period of time. Considering the assumptions escribed before the load factor for these cases would be of 89%, which would enable a high use of the equipment installed.

## 5.2 Production costs

### 5.2.1 Decentralized production

Considering the estimate electrolyser sizes for each blending ratio and its CAPEX (Table 17), the respective required investment for each blend ratio is shown in Table 25.

*Table 25: Decentralized production electrolyser CAPEX for different blend ratios.*

| <b>Electrolyser CAPEX [k€]</b> | <b>BR=5%</b> | <b>BR=10%</b> | <b>BR=15%</b> | <b>BR=20%</b> |
|--------------------------------|--------------|---------------|---------------|---------------|
| <b>System</b>                  | 56           | 115           | 181           | 251           |
| <b>Stacks</b>                  | 24           | 50            | 77            | 107           |
| <b>Total</b>                   | 80           | 165           | 258           | 358           |

To estimate the production costs, the water, electricity, O&M and natural gas expenses considerate are presented in Table 26, Table 27 and Table 28.

Table 26: Water volume consumed and expenses, decentralized production.

|               | H2O volume [m³] | Costs [k€] |
|---------------|-----------------|------------|
| <b>BR=5%</b>  | 103             | 0,18489    |
| <b>BR=10%</b> | 213             | 0,38371    |
| <b>BR=15%</b> | 332             | 0,59813    |
| <b>BR=20%</b> | 461             | 0,83003    |

Addressing now the electricity costs of the hydrogen production process, having the electricity price,  $E_{price}$ , the electrolyser specific consumption (efficiency),  $c_{el}$ , and the total hydrogen produced,  $m_{H_2}$ , this expense is determined by equation (7).

$$E_{costs} = E_{price} \times c_{el} \times m_{H_2} \text{ [€]} \quad (7)$$

Table 27: Electricity costs.

|                | $c_{el}$ [kWh/kg] | Costs [k€] |
|----------------|-------------------|------------|
| <b>BR=5%</b>   | 55                | 33,89      |
| <b>BR=10%</b>  |                   | 70,35      |
| <b>BR=15%</b>  |                   | 109,65     |
| <b>BR=20%</b>  |                   | 152,17     |
| <b>BR=100%</b> |                   | 2188,15    |

The operation and maintenance of the electrolyser, as mentioned in the electrolyser inputs, is 2% of the total CAPEX of the installation.

Table 28: O&M costs, decentralized production.

|                     | <b>BR=5%</b> | <b>BR=10%</b> | <b>BR=15%</b> | <b>BR=20%</b> |
|---------------------|--------------|---------------|---------------|---------------|
| <b>O&amp;M [k€]</b> | 2            | 3             | 5             | 7             |

It is also necessary to assess the costs with natural gas. This way, in Table 29, is presented the amount of natural gas consumed, nowadays and for each of the blend

percentages. In Table 30 are exhibited the current natural gas prices Amcor pays and the costs each blend ratio originates.

*Table 29: Natural gas consumptions.*

|               | <b>NG consumed [GWh]</b> |
|---------------|--------------------------|
| <b>BR=0%</b>  | 26,28                    |
| <b>BR=5%</b>  | 25,88                    |
| <b>BR=10%</b> | 25,44                    |
| <b>BR=15%</b> | 24,97                    |
| <b>BR=20%</b> | 24,46                    |

*Table 30: Natural gas costs.*

|                | <b>NG price [€/MWh]</b> | <b>Costs [€]</b> |
|----------------|-------------------------|------------------|
| <b>BR=0%</b>   | 25,23                   | 663 141          |
| <b>BR=5%</b>   |                         | 652 952          |
| <b>BR=10%</b>  |                         | 641 904          |
| <b>BR=15%</b>  |                         | 629 989          |
| <b>BR=20%</b>  |                         | 617 103          |
| <b>BR=100%</b> |                         | 0,00             |

Using these costs estimates, the levelized cost of hydrogen (LCOH) was calculated, which can vary according to the price of some of the OPEX expenses, such as electricity and water. However, as the variation of the price of water doesn't introduce significant differences in the LCOH, only electricity price variations were considered.

In Figure 43, is presented the graph showing the variation of the LCOH with the electricity price. The blue line represents the blend ratio of 5% and 10%, where it was considered that no alterations to the existing equipment had to be made, while the red and green lines represent the blend ratios of 15% and 20%, respectively, where it is necessary to make some adjustments to the burners, an additional investment, was required.

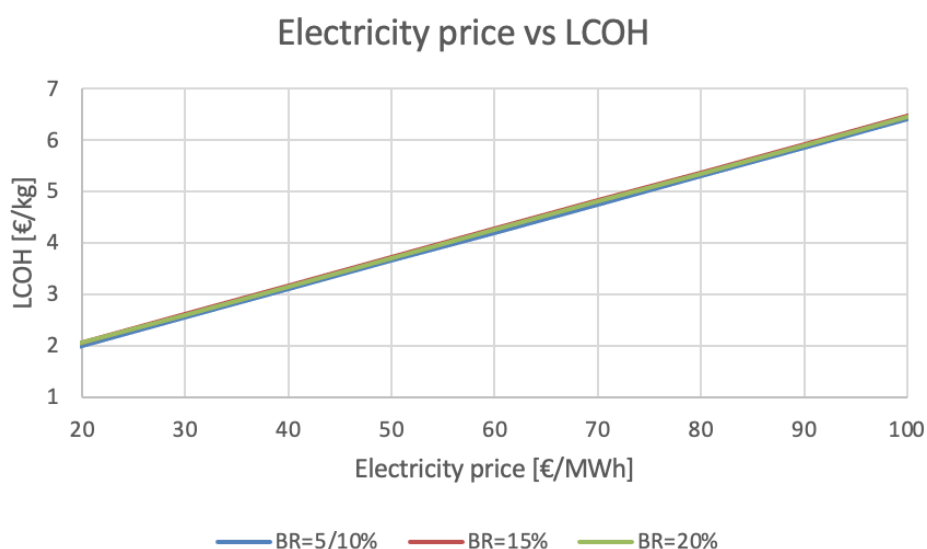


Figure 43: LCOH variations with the price of electricity.

By analyzing the figure above, it's understood that the changes that need to happen and the additional investments needed for it, don't have that big of an impact in the LCOH for the situation when the blend ratio is between 15% and 20% as, for each analyzed electricity price, the price of hydrogen only increases by 0,07€ comparing to a blend ratio of 15% and 0,05€ in compared to 20%. An explanation for this is simply the fact that the magnitude of the investment made to adjust the burners is much smaller than the overall investment in the hydrogen production unit.

Another factor that influences the project's feasibility and the costs associated with it is the natural gas consumed/avoided in each case and the associated amounts spent or saved with it. So, in Table 31, is shown the amount of natural gas saved for each scenario, and the respective cost reduction it promotes.

Table 31: Natural gas savings.

|                | NG avoided [GWh] | NG costs reduction [€] |
|----------------|------------------|------------------------|
| <b>BR=0%</b>   | 0,00             | 0,00                   |
| <b>BR=5%</b>   | 0,4              | 10 189                 |
| <b>BR=10%</b>  | 0,84             | 21 237                 |
| <b>BR=15%</b>  | 1,31             | 33 152                 |
| <b>BR=20%</b>  | 1,82             | 46 038                 |
| <b>BR=100%</b> | 26,28            | 663 141                |

The relation between what is saved by avoiding the natural gas usage and what is spent producing the hydrogen is what will dictate the profitability of the project and assess if the introduction of hydrogen can or cannot be a competitive advantage.

### 5.2.2 Centralized production

For the centralized production scenario, the electrolyser size was defined as 10MW and its CAPEX as 650€/kW so, the investment needed for the equipment in this case, is presented in Table 32.

*Table 32: Centralized production electrolyser CAPEX.*

| <b>Electrolyser CAPEX [k€]</b> | <b>10 MW Electrolyser</b> |
|--------------------------------|---------------------------|
| <b>System</b>                  | 4550                      |
| <b>Stacks</b>                  | 1950                      |
| <b>Total</b>                   | 6500                      |

For the centralized production scenario, the OPEX costs considered are presented in Table 33.

*Table 33: OPEX centralized production.*

| <b>Expense</b> | <b>Costs [€]</b> |
|----------------|------------------|
| Water          | 28 382           |
| Electricity    | 5 203 440        |
| O&M            | 130 000          |

In addition to the costs previously discussed, the transportation of the produced hydrogen from the production site to Amcor's facilities also had to be considered.

For the transportation costs there are, then, some scenarios that will be analyzed and some factors will vary. In the first scenario, it is considered that the pipelines will only transport the amount of hydrogen required to supply Amcor and, for the second scenario, it is considered that the pipeline will be shared with other hydrogen consumers and as such will transport all the hydrogen produced by the 10MW electrolyser, and only a portion of that is consumed by Amcor.

Additionally, for each scenario, two cases were considered. The first case compares the transport by a new hydrogen pipeline and the second by a repurposed natural gas

pipeline and, for each case, two different transportation distances were studied. All the variations will be done for each of the blend ratios under study.

It these scenarios, as the transportation inserts large costs to the economic model and given that the variation of the electricity price in the LCOH has already been assessed in the decentralized production analysis, a value of 60€/MWh was considered for the electricity price.

The centralized production, as it is done in a bigger scale, it is expected the LCOH to be lower than for the decentralized production scenario. Thus, this was proven will the determination of the cost of producing hydrogen without the transportation, which was 3,79€/kg.

This value, when compared to the equivalent, in decentralized production (same electricity price), is lower, as for blend ratios of 5% and 10% the LCOH is 4,2€/kg, for 15% is 4,27€/kg and for a blend ratio of 20%, the LCOH is 4,25€/kg.

### **SCENARIO 1:**

The results presented below regard the assumption that all the transportation costs relate to Amcor's demand.

As the amount paid for the transport is always the same, regardless of the amount of hydrogen transported and, this way, regardless of the blend ratio, the costs associated with transporting hydrogen for scenario 1, for 10km and 20km for new and repurposed pipelines respectively are presented in Table 34 and Table 35.

*Table 34: Transportation costs, M€, considering new pipelines to transport only the amount required by Amcor.*

| Distance [km] | Costs [M€] |
|---------------|------------|
| 10            | 22         |
| 20            | 44         |

*Table 35: Transportation costs, M€, considering repurposed pipelines to transport only the amount required by Amcor.*

| Distance [km] | Costs [M€] |
|---------------|------------|
| 10            | 4          |
| 20            | 8          |

As can be concluded by the analysis of the tables above, the LCOH associated with transporting hydrogen by a new pipeline rather than doing it through a repurposed natural gas pipeline will be much higher. In fact, the costs of repurposing pipelines (including decommissioning from NG operation, water pressure tests, replacement of fittings and dismantling of connections, etc.) is estimated at around 10-15% of the cost of construction of new hydrogen lines [36], which has a huge impact in the final hydrogen costs for each alternative, as proven.

The fact that the production costs themselves are cheap (cheaper than decentralized production) because of the large-scale production process associated is not sufficient to compensate the obtained high costs of transportation of these small volumes of hydrogen.

Therefore, for this scenario 1 in study, the LCOH obtained, already with the transportation was 17,74 €/kg and 31,69€/kg for new pipelines for 10km and 20km respectively, and 6,32 €/kg and 8,86 €/kg for repurposed pipelines for 10km and 20km respectively.

Additionally, and as expected considering the prices, as the transport distance increases, the growth rate for new pipelines is higher than for repurposed ones, which means that for longer distances the costs of transporting hydrogen will have a much greater impact in the new pipelines scenario rather than in the repurposed one. As such, the establishment of a transportation and distribution grid based on pipelines will only be a possibility once the amount of hydrogen being transported is much higher.

## **SCENARIO 2:**

The results presented below regard the assumption that the transportation costs refer to the total amount of hydrogen produced, and only a portion of it concerns to Amcor.

Considering that the total amount of hydrogen produced with the 10MW electrolyser installed is 1576800 kg, in Table 36 and Table 37 are presented the fraction of the costs for Amcor's demand for each scenario.

*Table 36: Transportation costs by new pipeline, k€, considering only the share of hydrogen that Amcor would use.*

| <b>Distance [km]</b> | <b>BR=5%</b> | <b>BR=10%</b> | <b>BR=15%</b> | <b>BR=20%</b> |
|----------------------|--------------|---------------|---------------|---------------|
| <b>10</b>            | 140          | 300           | 460           | 640           |
| <b>20</b>            | 290          | 590           | 920           | 1280          |

Table 37: Transportation costs by repurposed pipeline, k€, considering only the share of hydrogen that Amcor would use.

| Distance [km] | BR=5% | BR=10% | BR=15% | BR=20% |
|---------------|-------|--------|--------|--------|
| 10            | 26,06 | 54,08  | 84,30  | 117,0  |
| 20            | 52,12 | 108,2  | 168,6  | 234,0  |

Therefore, the LCOH values for this second scenario are shown in Table 38 and Table 39, for new and repurposed pipelines respectively.

Table 38: LCOH assuming hydrogen transport by a new pipeline, €/kg, considering only the share of hydrogen that Amcor would use.

| Distance [km] | BR=5% | BR=10% | BR=15% | BR=20% |
|---------------|-------|--------|--------|--------|
| 10            | 3,88  | 3,98   | 4,08   | 4,20   |
| 20            | 3,97  | 4,16   | 4,37   | 4,60   |

Table 39: LCOH assuming hydrogen transport by a repurposed natural gas pipeline, €/kg, considering only the share of hydrogen that Amcor would use.

| Distance [km] | BR=5% | BR=10% | BR=15% | BR=20% |
|---------------|-------|--------|--------|--------|
| 10            | 3,81  | 3,82   | 3,84   | 3,86   |
| 20            | 3,82  | 3,86   | 3,90   | 3,94   |

Firstly, as for this second case of study the transportation costs were assumed to be for the total amount produced by the electrolyser and the amount paid by Amcor was only a corresponding portion to their necessities, each blend ratio and distance combination has a different LCOH value.

It's possible to see that for both new and repurposed pipelines, besides, obviously, the lower values, the growth ratio between the different distances analyzed has decreased, what means that for pipelines transporting larger quantities of hydrogen, the price per unit, €/kg, decreases as the amount of hydrogen transported increases, always inside the pipeline volume limit of course.

To sum up, the results presented in this section allow the conclusion that for a centralized production scenario, the key to economic viability is indeed associated with the transport of hydrogen and the costs that derive from it. In fact, the production costs alone of a centralized scenario are lower when compared to the local production unit, however the need for transport push the LCOH to higher values.

Additionally, by reviewing and comparing the results obtained for the two cases addressed in this section, it is possible to conclude that as the volume of hydrogen to be transported increases the price per unit associated with it decreases, which proves that the transportation of hydrogen by pipeline, as studied, is a method that becomes more and more viable as the amount of hydrogen to transport increases. However, for this to be a reality, there would be a need for Amcor to have other industries nearby willing to consume hydrogen and share the costs with the pipelines, which may be difficult in this early stage of the hydrogen market development.

## 5.3 H2 competitiveness

### 5.3.1 Decentralized production

Regarding the competitiveness of the proposed solutions for the decentralized hydrogen production, when compared to the utilization of natural gas, an analysis was made to compare the competitive space of each resource, using the net present value (NPV) of each scenario.

Therefore, when performing the economic analysis, in the revenue area, the amount of natural gas avoided in each case and its price was considered. If the NPV calculated was positive, it means that what is saved by not using natural gas is greater than what is spent to produce hydrogen, so the hydrogen is more beneficial than the natural gas. If, on the other hand, the NPV turns out to be negative, the project is further away from economic competitiveness, and the more negative it is, the further away it is.

This way, to perform the mentioned analysis, the prices of electricity and natural gas were used as sensitivities, and the Table 40, Table 41, Table 42 and Table 43 present the results obtained.

The color scheme used in the tables below considers that when a cell is colored red, the investment is not attractive for hydrogen, as the use of natural gas is more competitive. However, the green cells highlight scenarios in which the introduction of hydrogen is beneficial when comparing to only natural gas.

Table 40: Competitiveness of a BR=5%.

|                            |          | Natural gas prices [€/MWh] |      |      |      |      |      |      |      |
|----------------------------|----------|----------------------------|------|------|------|------|------|------|------|
| Electricity prices [€/MWh] | NPV [k€] | 25,23                      | 30   | 40   | 50   | 60   | 70   | 80   | 90   |
|                            | 10       | -68                        | -41  | 15   | 72   | 128  | 184  | 241  | 297  |
|                            | 20       | -148                       | -121 | -64  | -8   | 48   | 105  | 161  | 218  |
|                            | 30       | -227                       | -200 | -144 | -88  | -31  | 25   | 81   | 138  |
|                            | 40       | -307                       | -280 | -224 | -167 | -111 | -55  | 2    | 58   |
|                            | 50       | -387                       | -360 | -303 | -247 | -191 | -134 | -78  | -21  |
|                            | 60       | -466                       | -439 | -383 | -327 | -270 | -214 | -157 | -101 |

Table 41: Competitiveness of a BR=10%.

|                            |          | Natural gas prices [€/MWh] |      |      |      |      |      |      |      |
|----------------------------|----------|----------------------------|------|------|------|------|------|------|------|
| Electricity prices [€/MWh] | NPV [k€] | 25,23                      | 30   | 40   | 50   | 60   | 70   | 80   | 90   |
|                            | 10       | -138                       | -81  | 37   | 156  | 274  | 392  | 511  | 629  |
|                            | 20       | -303                       | -247 | -128 | -10  | 109  | 227  | 345  | 464  |
|                            | 30       | -468                       | -412 | -293 | -175 | -57  | 62   | 180  | 299  |
|                            | 40       | -634                       | -577 | -459 | -340 | -222 | -103 | -15  | 133  |
|                            | 50       | -799                       | -742 | -624 | -506 | -387 | -269 | -150 | -32  |
|                            | 60       | -964                       | -908 | -789 | -671 | -552 | -434 | -316 | -197 |

Table 42: Competitiveness of a BR=15%.

|                            |    | Natural gas prices [€/MWh] |       |       |       |      |      |      |      |
|----------------------------|----|----------------------------|-------|-------|-------|------|------|------|------|
| NPV [k€]                   |    | 25,23                      | 30    | 40    | 50    | 60   | 70   | 80   | 90   |
| Electricity prices [€/MWh] | 10 | -245                       | -157  | 28    | 212   | 397  | 582  | 766  | 951  |
|                            | 20 | -503                       | -415  | -230  | -45   | 139  | 324  | 509  | 669  |
|                            | 30 | -760                       | -672  | -487  | -303  | -118 | 67   | 251  | 436  |
|                            | 40 | -1017                      | -930  | -745  | -560  | -376 | -191 | -7   | 178  |
|                            | 50 | -1275                      | -1187 | -1003 | -818  | -633 | -449 | -264 | -79  |
|                            | 60 | -1533                      | -1445 | -1260 | -1076 | -891 | -706 | -522 | -337 |

Table 43: Competitiveness of a BR=20%.

|                            |             | Natural gas prices [€/MWh] |       |       |       |       |      |      |      |
|----------------------------|-------------|----------------------------|-------|-------|-------|-------|------|------|------|
|                            | NPV<br>[k€] | 25,23                      | 30    | 40    | 50    | 60    | 70   | 80   | 90   |
| Electricity prices [€/MWh] | 10          | -327                       | -205  | 52    | 308   | 565   | 821  | 1078 | 1334 |
|                            | 20          | -688                       | -562  | -306  | -49   | 207   | 464  | 720  | 977  |
|                            | 30          | -1042                      | -917  | -663  | -407  | -150  | 106  | 363  | 619  |
|                            | 40          | -1400                      | -1277 | -1021 | -764  | -508  | -251 | 5    | 262  |
|                            | 50          | -1757                      | -1635 | -1378 | -1122 | -865  | -609 | -352 | -96  |
|                            | 60          | -2115                      | -1992 | -1736 | -1379 | -1223 | -966 | -708 | -453 |

By the analysis of the tables above, it can be concluded that for the decentralized production scenarios under study, the introduction of hydrogen is only viable for the combination of high natural gas prices with low electricity prices. From Amcor's point of view, reaching these electricity and natural gas prices, to achieve hydrogen viability, would be really difficult, given the prices they pay now.

Another conclusion that can be withdrawn, regarding the fact that as the blend ratio increases the values painted in green tend to become more and more positive whereas the negative values tend to become even more negative, is that because the hydrogen has successively more impact due to higher volumes, for the same electricity prices, the costs will be higher, just as with the decrease of natural gas percentages, for the same price, the respective costs will be lower. Consequently, it is possible to conclude

the existence of a line from which hydrogen starts to be beneficial, and for the same electricity and natural gas prices configurations, the values under the line get more negative with the increase of the blend ratio, and the values above the line get more and more positive.

To analyze these competitiveness limits, in Figure 44 is presented a graph that shows the natural gas and electricity price combinations that are viable for the introduction of hydrogen or if, by contrast, it is better to have only natural gas. The area above the line represents where hydrogen is competitive and under the line the situations where it isn't.

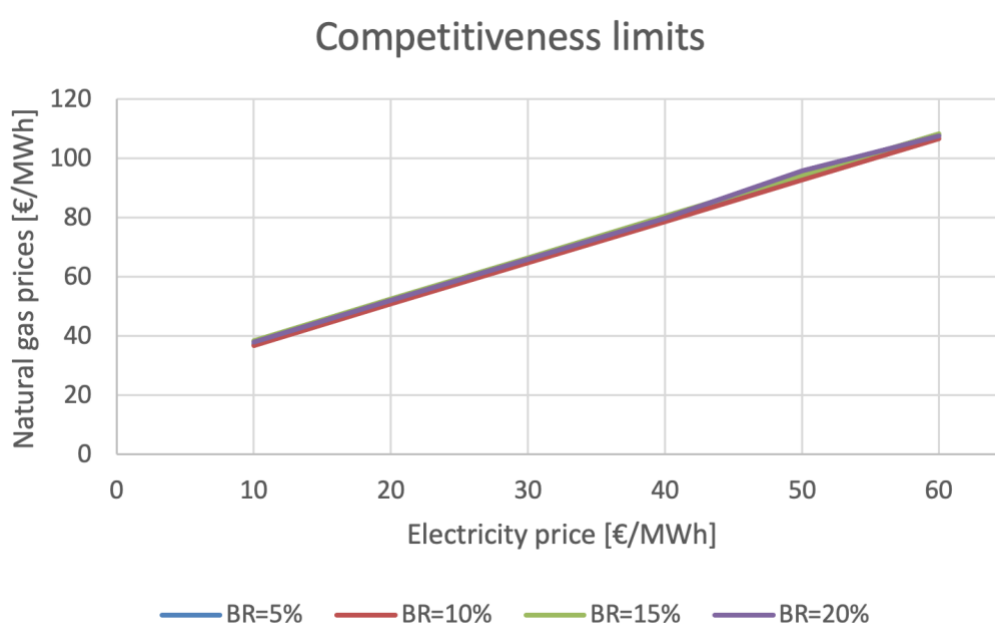


Figure 44: Hydrogen competitiveness limits.

To achieve a competitive scenario with hydrogen, a combination of high natural gas and low electricity prices need to happen, prices which are far from the current situation. Thus, a factor that can open the door for hydrogen competitiveness in conditions similar to the current is considering the CO<sub>2</sub> emissions, and the price to pay for them.

In fact, making industries pay an additional amount for the emitted CO<sub>2</sub> is a measure that can promote decarbonization and make energy sources such as hydrogen more economically viable. According to this logic, in Table 44, Table 45, Table 46 and Table 47 are presented the amounts Amcor had to pay per ton of emitted CO<sub>2</sub>, so that each of the scenarios regarding the introduction of hydrogen would be viable.

Table 44: CO2 prices for hydrogen competitiveness, BR=5%.

|                            |    | Natural gas prices [€/MWh] |       |     |     |     |     |    |    |    |
|----------------------------|----|----------------------------|-------|-----|-----|-----|-----|----|----|----|
|                            |    | [€/ton CO <sub>2</sub> ]   | 25,23 | 30  | 40  | 50  | 60  | 70 | 80 | 90 |
| Electricity prices [€/MWh] | 10 | 37                         | 23    | -   | -   | -   | -   | -  | -  | -  |
|                            | 20 | 81                         | 66    | 35  | 4   | -   | -   | -  | -  | -  |
|                            | 30 | 124                        | 109   | 70  | 48  | 17  | -   | -  | -  | -  |
|                            | 40 | 168                        | 153   | 122 | 91  | 61  | 30  | -  | -  | -  |
|                            | 50 | 211                        | 196   | 166 | 135 | 104 | 73  | 43 | 12 |    |
|                            | 60 | 255                        | 240   | 209 | 198 | 148 | 117 | 86 | 55 |    |

Table 45: CO2 prices for hydrogen competitiveness, BR=10%.

|                            |    | Natural gas prices [€/MWh] |       |     |     |     |     |    |    |    |
|----------------------------|----|----------------------------|-------|-----|-----|-----|-----|----|----|----|
|                            |    | [€/ton CO <sub>2</sub> ]   | 25,23 | 30  | 40  | 50  | 60  | 70 | 80 | 90 |
| Electricity prices [€/MWh] | 10 | 33                         | 19    | -   | -   | -   | -   | -  | -  | -  |
|                            | 20 | 72                         | 59    | 30  | 2   | -   | -   | -  | -  | -  |
|                            | 30 | 111                        | 98    | 69  | 42  | 13  | -   | -  | -  | -  |
|                            | 40 | 150                        | 137   | 108 | 81  | 52  | 24  | -  | -  | -  |
|                            | 50 | 189                        | 176   | 148 | 120 | 91  | 64  | 36 | 8  |    |
|                            | 60 | 228                        | 215   | 186 | 159 | 130 | 103 | 75 | 46 |    |

Table 46: CO2 prices for hydrogen competitiveness, BR=15%.

|                            |    | Natural gas prices [€/MWh] |       |     |     |     |     |    |    |    |
|----------------------------|----|----------------------------|-------|-----|-----|-----|-----|----|----|----|
|                            |    | [€/ton CO <sub>2</sub> ]   | 25,23 | 30  | 40  | 50  | 60  | 70 | 80 | 90 |
| Electricity prices [€/MWh] | 10 | 36                         | 23    | -   | -   | -   | -   | -  | -  | -  |
|                            | 20 | 73                         | 60    | 33  | 7   | -   | -   | -  | -  | -  |
|                            | 30 | 110                        | 97    | 71  | 44  | 17  | -   | -  | -  | -  |
|                            | 40 | 147                        | 135   | 108 | 81  | 54  | 28  | 1  | -  | -  |
|                            | 50 | 189                        | 176   | 149 | 123 | 96  | 69  | 42 | 16 | 16 |
|                            | 60 | 222                        | 209   | 183 | 156 | 129 | 102 | 75 | 49 | 49 |

Table 47: CO2 prices for hydrogen competitiveness, BR=20%.

|                            |    | Natural gas prices [€/MWh] |       |     |     |     |    |    |    |    |
|----------------------------|----|----------------------------|-------|-----|-----|-----|----|----|----|----|
|                            |    | [€/ton CO <sub>2</sub> ]   | 25,23 | 30  | 40  | 50  | 60 | 70 | 80 | 90 |
| Electricity prices [€/MWh] | 10 | 34                         | 21    | -   | -   | -   | -  | -  | -  | -  |
|                            | 20 | 70                         | 58    | 31  | 5   | -   | -  | -  | -  | -  |
|                            | 30 | 107                        | 95    | 68  | 42  | 15  | -  | -  | -  | -  |
|                            | 40 | 144                        | 131   | 105 | 79  | 52  | 26 | -  | -  | -  |
|                            | 50 | 181                        | 168   | 142 | 115 | 89  | 63 | 36 | 10 |    |
|                            | 60 | 217                        | 205   | 178 | 152 | 126 | 99 | 73 | 47 |    |

Considering that the EU Emissions Trading System (EU ETS), which today is around 90 €/ton of CO<sub>2</sub>, for a scenario of central natural gas and electricity prices, some configurations would already allow hydrogen to be viable. However, an increase of this price would enable more situations to be hydrogen viable.

### 5.3.2 Centralized production

In this section, the evaluation of the competitiveness of the centralized production scenario will be performed only for scenario 2, in which the transportation costs refer to the total amount of hydrogen produced, and only a portion of it concern to Amcor's supply, as scenario 1 is proven to be not economically viable.

For this competitiveness analysis, the strategy used was to calculate, considering the values for the avoided natural gas (GWh) presented in Table 31 and the costs with hydrogen, calculated by the LCOH multiplied by the hydrogen demand, in kg, the price natural gas would have to reach to be viable the utilization of hydrogen.

Thus, the results obtained for each blend ratio and situation studied are presented in Table 48, Table 49, Table 50 and Table 51 without considering savings from CO<sub>2</sub>.

It must be remembered that for the centralized production an electricity cost of 60 €/MWh was defined and so, the direct comparisons with the decentralized production scenario should be made with values regarding the same electricity price.

Table 48: H2 vs NG competitiveness (centralized production), BR=5%.

|                             |       | LCOH [€/kg] | Costs [€] | NG price for competitiveness [€/MWh] |
|-----------------------------|-------|-------------|-----------|--------------------------------------|
| <b>New pipelines</b>        | 10 km | 3,88        | 39854,97  | 99,6                                 |
|                             | 20 km | 3,97        | 40779,44  | 102,0                                |
| <b>Repurposed pipelines</b> | 10 km | 3,81        | 39135,94  | 97,8                                 |
|                             | 20 km | 3,82        | 39238,66  | 98,1                                 |

Table 49: H2 vs NG competitiveness (centralized production), BR=10%.

|                             |       | LCOH [€/kg] | Costs [€] | NG price for competitiveness [€/MWh] |
|-----------------------------|-------|-------------|-----------|--------------------------------------|
| <b>New pipelines</b>        | 10 km | 3,98        | 84849,22  | 101,0                                |
|                             | 20 km | 4,16        | 88686,62  | 105,6                                |
| <b>Repurposed pipelines</b> | 10 km | 3,82        | 81438,20  | 97,0                                 |
|                             | 20 km | 3,86        | 82290,95  | 98,0                                 |

Table 50: H2 vs NG competitiveness (centralized production), BR=15%.

|                             |       | LCOH [€/kg] | Costs [€] | NG price for competitiveness [€/MWh] |
|-----------------------------|-------|-------------|-----------|--------------------------------------|
| <b>New pipelines</b>        | 10 km | 4,08        | 135577,2  | 103,5                                |
|                             | 20 km | 4,37        | 145213,8  | 110,9                                |
| <b>Repurposed pipelines</b> | 10 km | 3,84        | 127602,0  | 97,4                                 |
|                             | 20 km | 3,90        | 129595,8  | 98,9                                 |

Table 51: H2 vs NG competitiveness (centralized production), BR=20%.

|                             |       | LCOH [€/kg] | Costs [€] | NG price for competitiveness [€/MWh] |
|-----------------------------|-------|-------------|-----------|--------------------------------------|
| <b>New pipelines</b>        | 10 km | 4,20        | 193672,5  | 106,4                                |
|                             | 20 km | 4,60        | 212117,5  | 116,5                                |
| <b>Repurposed pipelines</b> | 10 km | 3,86        | 177994,3  | 97,8                                 |
|                             | 20 km | 3,94        | 181683,3  | 99,8                                 |



## 6. Conclusions and future work

### 6.1 Conclusions

In the path to decarbonization and carbon neutrality, hydrogen can be a key energy vector, especially to sectors hard to decarbonize via direct electrification. In fact, the versatility that hydrogen shows as an energy carrier can be important to help tackle various energy challenges and its introduction by a lot of end-use sectors could potentiate a deployment of low carbon energy sources. However, a hydrogen-based energy transition will not happen overnight, and the need for a dedicated new supply infrastructure may limit hydrogen use to certain countries that decide to invest in this strategy and that have ambitious climate objectives.

The main objective of this work was to assess the potential of blending hydrogen in Amcor Flexibles PT natural gas grid, comparing two major approaches, a first one focusing on a decentralized hydrogen production in Amcor's facilities fully for self-consumption and a second approach analyzing a centralized hydrogen production scenario, with a larger-scale production unit and transportation of the hydrogen from the production site to Amcor's factory. For each approach, hydrogen blending ratios of 5%, 10%, 15% and 20% were considered.

The first step of the analysis was to perform a technical assessment on the use of hydrogen for each blending ratio. Considering a few initial assumptions, including real energy consumption data from Amcor and the gases thermo-physical properties, the amount of hydrogen required, the reduction of natural gas consumption and the size of the electrolyser needed were calculated, which varied from 0,1 MW for a blending ratio of 5% and 0,4 MW for a blending ratio of 20%.

As far as the study of centralized production is concerned, it wasn't necessary to size the electrolyser to use, because being a larger scale production infrastructure, it was assumed that a 10MW hydrogen production unit would be installed. However, as the blending ratios used were the same as in the decentralized production scenario, some of the technical results obtained in the previous phase had to be used to assess the percentage of production of the large-scale electrolyser was require, as in this case the volumes produced weren't all for self-consumption.

After the technical analysis' were completed, the economic study of each of the project scenarios was performed to assess its viability and the possibility of competing with the current situation in practice which is the use of 100% of natural gas.

As expected, as large-scale production usually turns out to be cheaper that producing in small quantities, because a bigger size technology reflects a lower investment per kW, for the centralized production scenario, the costs of producing hydrogen for the centralized production scenario (excluding the transport) are cheaper that the same

process done by a decentralized solution. In fact, for an electricity price of 60 €/MWh, for example, the LCOH for the decentralized production scenario is 4,2 €/kg (BR=5%/10%), 4,27 €/kg (BR=15%) and 4,25 €/kg (BR=20%), while for the centralized production scenarios, this value was around 3,79 €/kg. The LCOH varies with the variation of the electricity price, increasing when its higher and decreasing when the price of electricity is lower.

However, the analysis of the centralized production demonstrated that the costs of hydrogen transport could significantly influence the final cost of the hydrogen. When considering a dedicated hydrogen pipeline to transport only the hydrogen that would be used by Amcor, the results showed that the costs would be so high that the centralized production would lose its competitiveness, reaching LCOH of 17,74 €/kg and 31,69€/kg for new and repurposed pipelines respectively. Alternatively, if the transport and distribution costs are able to be shared with other consumers, then the total costs of producing and delivering hydrogen in a centralized manner becomes competitive, reaching LCOH between 3,88 and 4,60 €/kg for a new pipeline and between 3,81 and 3,94 €/kg for a repurposed pipeline. This allows to draw the conclusion that, having a large-scale production facility, enabling large amounts of hydrogen to be produce and delivered is more economically viable and beneficial than having multiple small-scale decentralized production units, if there is sufficient volume to divide the logistics costs.

Regarding the comparison of the introduction of hydrogen with the current state of energy supply only by natural gas, the results show that to achieve a situation in which the injection of hydrogen in the gas grid is economically viable compared to using only natural gas would require facing an attractive price combination that brings together high natural gas prices with low electricity prices. However, comparing the current prices paid by Amcor, this does not seem to be possible, as generally a price of around 80 €/MWh of natural gas would be required for an electricity price of 50 €/MWh, considering the current price of CO<sub>2</sub> allowances that is currently of ~90 €/MWh.

Ultimately, it is clear that hydrogen will play an important role in the energy transition that happening in the world and will probably be one of the most important energy vectors in a low carbon future. With that said, bearing in mind the results obtained in this study, it is important to adopt strategies to make hydrogen more viable to promote the decrease of the depend of natural gas, such as additional costs for industries for their CO<sub>2</sub> emissions, which will increase the total natural gas prices, and it is also important, in this transitory phase, to start investing in the implementation of hydrogen technologies so that their technologies can be developed and their costs reduced.

## 6.2 Future work

For the decentralized production scenario and having developed this study based on Amcor's industrial requirements and energy consumptions, it would be interesting to

put into practice the study carried out and obtain a more detailed project concerning the installation of the technologies and infrastructures mentioned in their facilities.

With that said, it would be enlightening to determine:

- The exact location in Amcor facilities where the production unit would be installed, this assuming they already have the space required for it, otherwise it would also be important to determine the costs associated with acquiring the space;
- Understand the permissions needed and the costs that they entail;
- Assess personnel / administrative costs including overheads.

Regarding the centralized production scenario, as the production site was considered close to Amcor's facilities, it would be interesting to evaluate the costs of producing hydrogen in a more distant location, assuming that production facility would also be supplying other clients in further places, and the production location should be more uniform for everyone. This way, the future study would consist in a even larger-scale production unit, >10 MW, to supply multiple industries and clients.

To finish, for both cases it would also be interesting the study the possibility of storing hydrogen, as this is one the best characteristics of this element. A technical analysis would have to be performed to understand the viable hydrogen amounts that could be stored, and the costs associated with it would have to be analyzed as well.



## Annex A

In Annex A are presented the tables with the blend volumes, hydrogen volumes, hydrogen mass produced and hourly production for the different blend ratios, for the decentralized production scenario.

*Table A. 1: Results for the blend volume, hydrogen volume, hydrogen mass and hourly hydrogen production for a BR=5%.*

|                 | <b>Vblend [Nm<sup>3</sup>]</b> | <b>V H<sub>2</sub> [Nm<sup>3</sup>]</b> | <b>m H<sub>2</sub> [kg]</b> | <b>Prod [kg]</b> |
|-----------------|--------------------------------|-----------------------------------------|-----------------------------|------------------|
| <b>Jan/2020</b> | 191146,6                       | 9557,3                                  | 850,6                       | 1,14             |
| <b>Feb/2020</b> | 193375,8                       | 9668,8                                  | 860,5                       | 1,24             |
| <b>Mar/2020</b> | 205309,0                       | 10265,4                                 | 913,6                       | 1,23             |
| <b>Apr/2020</b> | 188011,6                       | 9400,6                                  | 836,7                       | 1,16             |
| <b>May/2020</b> | 190734,7                       | 9536,7                                  | 848,8                       | 1,14             |
| <b>Jun/2020</b> | 182732,6                       | 9136,6                                  | 813,2                       | 1,13             |
| <b>Jul/2020</b> | 186709,1                       | 9335,5                                  | 830,9                       | 1,12             |
| <b>Aug/2020</b> | 184532,8                       | 9226,6                                  | 821,2                       | 1,10             |
| <b>Sep/2020</b> | 201005,8                       | 10050,3                                 | 894,5                       | 1,24             |
| <b>Oct/2020</b> | 213889,0                       | 10694,4                                 | 951,8                       | 1,28             |
| <b>Nov/2020</b> | 209918,0                       | 10495,9                                 | 934,1                       | 1,30             |
| <b>Dec/2020</b> | 175170,3                       | 8758,5                                  | 779,5                       | 1,05             |
| <b>Jan/2021</b> | 181850,7                       | 9092,5                                  | 809,2                       | 1,09             |
| <b>Feb/2021</b> | 169791,1                       | 8489,6                                  | 755,6                       | 1,12             |
| <b>Mar/2021</b> | 207136,4                       | 10356,8                                 | 921,8                       | 1,24             |
| <b>Apr/2021</b> | 189828,6                       | 9491,4                                  | 844,7                       | 1,17             |
| <b>May/2021</b> | 206037,0                       | 10301,8                                 | 916,9                       | 1,23             |
| <b>Jun/2021</b> | 178553,1                       | 8927,7                                  | 794,6                       | 1,10             |
| <b>Jul/2021</b> | 208928,9                       | 10446,4                                 | 929,7                       | 1,25             |
| <b>Aug/2021</b> | 139847,5                       | 6992,4                                  | 622,3                       | 0,84             |
| <b>Sep/2021</b> | 203362,5                       | 10168,1                                 | 905,0                       | 1,26             |
| <b>Oct/2021</b> | 206255,7                       | 10312,8                                 | 917,8                       | 1,23             |
| <b>Nov/2021</b> | 210584,3                       | 10529,2                                 | 937,1                       | 1,30             |
| <b>Dec/2021</b> | 191853,0                       | 9592,7                                  | 853,7                       | 1,15             |

*Table A. 2: Results for the blend volume, hydrogen volume, hydrogen mass and hourly hydrogen production for a BR=10%.*

|                 | <b>Vblend [Nm<sup>3</sup>]</b> | <b>V H<sub>2</sub> [Nm<sup>3</sup>]</b> | <b>m H<sub>2</sub> [kg]</b> | <b>Prod [kg]</b> |
|-----------------|--------------------------------|-----------------------------------------|-----------------------------|------------------|
| <b>Jan/2020</b> | 198351,8                       | 19835,2                                 | 1765,3                      | 2,37             |

|                 |          |         |        |      |
|-----------------|----------|---------|--------|------|
| <b>Feb/2020</b> | 200665,0 | 20066,5 | 1785,9 | 2,57 |
| <b>Mar/2020</b> | 213048,0 | 21304,8 | 1896,1 | 2,55 |
| <b>Apr/2020</b> | 195098,5 | 19509,9 | 1736,4 | 2,41 |
| <b>May/2020</b> | 197924,3 | 19792,4 | 1761,5 | 2,37 |
| <b>Jun/2020</b> | 189620,5 | 18962,1 | 1687,6 | 2,34 |
| <b>Jul/2020</b> | 193746,9 | 19374,7 | 1724,3 | 2,32 |
| <b>Aug/2020</b> | 191488,6 | 19148,9 | 1704,2 | 2,29 |
| <b>Sep/2020</b> | 208582,6 | 20858,3 | 1856,4 | 2,58 |
| <b>Oct/2020</b> | 221951,4 | 22195,1 | 1975,4 | 2,66 |
| <b>Nov/2020</b> | 217830,7 | 21783,1 | 1938,7 | 2,69 |
| <b>Dec/2020</b> | 181773,2 | 18177,3 | 1617,8 | 2,17 |
| <b>Jan/2021</b> | 188705,5 | 18870,5 | 1679,5 | 2,26 |
| <b>Feb/2021</b> | 176191,2 | 17619,1 | 1568,1 | 2,33 |
| <b>Mar/2021</b> | 214944,3 | 21494,4 | 1913,0 | 2,57 |
| <b>Apr/2021</b> | 196984,0 | 19698,4 | 1753,2 | 2,43 |
| <b>May/2021</b> | 213803,4 | 21380,3 | 1902,9 | 2,56 |
| <b>Jun/2021</b> | 185283,5 | 18528,4 | 1649,0 | 2,29 |
| <b>Jul/2021</b> | 216804,4 | 21680,4 | 1929,6 | 2,59 |
| <b>Aug/2021</b> | 145119,0 | 14511,9 | 1291,6 | 1,74 |
| <b>Sep/2021</b> | 211028,1 | 21102,8 | 1878,1 | 2,61 |
| <b>Oct/2021</b> | 214030,4 | 21403,0 | 1904,9 | 2,56 |
| <b>Nov/2021</b> | 218522,2 | 21852,2 | 1944,8 | 2,70 |
| <b>Dec/2021</b> | 199084,8 | 19908,5 | 1771,9 | 2,38 |

Table A. 3: Results for the blend volume, hydrogen volume, hydrogen mass and hourly hydrogen production for a BR=15%.

|                 | <b>Vblend [Nm<sup>3</sup>]</b> | <b>V H<sub>2</sub> [Nm<sup>3</sup>]</b> | <b>m H<sub>2</sub> [kg]</b> | <b>Prod [kg]</b> |
|-----------------|--------------------------------|-----------------------------------------|-----------------------------|------------------|
| <b>Jan/2020</b> | 206121,4                       | 30918,2                                 | 2751,7                      | 3,70             |
| <b>Feb/2020</b> | 208525,2                       | 31278,8                                 | 2783,8                      | 4,00             |
| <b>Mar/2020</b> | 221393,2                       | 33209,0                                 | 2955,6                      | 3,97             |
| <b>Apr/2020</b> | 202740,7                       | 30411,1                                 | 2706,6                      | 3,76             |
| <b>May/2020</b> | 205677,1                       | 30851,6                                 | 2745,8                      | 3,69             |
| <b>Jun/2020</b> | 197048,1                       | 29557,2                                 | 2630,6                      | 3,65             |
| <b>Jul/2020</b> | 201336,2                       | 30200,4                                 | 2687,8                      | 3,61             |
| <b>Aug/2020</b> | 198989,4                       | 29848,4                                 | 2656,5                      | 3,57             |
| <b>Sep/2020</b> | 216752,9                       | 32512,9                                 | 2893,7                      | 4,02             |
| <b>Oct/2020</b> | 230645,4                       | 34596,8                                 | 3079,1                      | 4,14             |

|                 |          |         |        |      |
|-----------------|----------|---------|--------|------|
| <b>Nov/2020</b> | 226363,3 | 33954,5 | 3022,0 | 4,20 |
| <b>Dec/2020</b> | 188893,4 | 28334,0 | 2521,7 | 3,39 |
| <b>Jan/2021</b> | 196097,2 | 29414,6 | 2617,9 | 3,52 |
| <b>Feb/2021</b> | 183092,8 | 27463,9 | 2444,3 | 3,64 |
| <b>Mar/2021</b> | 223363,8 | 33504,6 | 2981,9 | 4,01 |
| <b>Apr/2021</b> | 204700,1 | 30705,0 | 2732,7 | 3,80 |
| <b>May/2021</b> | 222178,2 | 33326,7 | 2966,1 | 3,99 |
| <b>Jun/2021</b> | 192541,2 | 28881,2 | 2570,4 | 3,57 |
| <b>Jul/2021</b> | 225296,8 | 33794,5 | 3007,7 | 4,04 |
| <b>Aug/2021</b> | 150803,4 | 22620,5 | 2013,2 | 2,71 |
| <b>Sep/2021</b> | 219294,2 | 32894,1 | 2927,6 | 4,07 |
| <b>Oct/2021</b> | 222414,1 | 33362,1 | 2969,2 | 3,99 |
| <b>Nov/2021</b> | 227081,8 | 34062,3 | 3031,5 | 4,21 |
| <b>Dec/2021</b> | 206883,1 | 31032,5 | 2761,9 | 3,71 |

Table A. 4: Results for the blend volume, hydrogen volume, hydrogen mass and hourly hydrogen production for a BR=20%.

|                 | <b>Vblend [Nm<sup>3</sup>]</b> | <b>V H<sub>2</sub> [Nm<sup>3</sup>]</b> | <b>m H<sub>2</sub> [kg]</b> | <b>Prod [kg]</b> |
|-----------------|--------------------------------|-----------------------------------------|-----------------------------|------------------|
| <b>Jan/2020</b> | 214524,5                       | 42904,9                                 | 3818,5                      | 5,13             |
| <b>Feb/2020</b> | 217026,3                       | 43405,3                                 | 3863,1                      | 5,55             |
| <b>Mar/2020</b> | 230418,9                       | 46083,8                                 | 4101,5                      | 5,51             |
| <b>Apr/2020</b> | 211006,0                       | 42201,2                                 | 3755,9                      | 5,22             |
| <b>May/2020</b> | 214062,1                       | 42812,4                                 | 3810,3                      | 5,12             |
| <b>Jun/2020</b> | 205081,3                       | 41016,3                                 | 3650,4                      | 5,07             |
| <b>Jul/2020</b> | 209544,2                       | 41908,8                                 | 3729,9                      | 5,01             |
| <b>Aug/2020</b> | 207101,7                       | 41420,3                                 | 3686,4                      | 5,95             |
| <b>Sep/2020</b> | 225589,4                       | 45117,9                                 | 4015,5                      | 5,58             |
| <b>Oct/2020</b> | 240048,3                       | 48009,7                                 | 4272,9                      | 5,74             |
| <b>Nov/2020</b> | 235591,6                       | 47118,3                                 | 4193,5                      | 5,82             |
| <b>Dec/2020</b> | 196594,2                       | 39318,8                                 | 3499,4                      | 5,70             |
| <b>Jan/2021</b> | 204091,6                       | 40818,3                                 | 3632,8                      | 5,88             |
| <b>Feb/2021</b> | 190557,0                       | 38111,4                                 | 3391,9                      | 5,05             |
| <b>Mar/2021</b> | 232469,9                       | 46494,0                                 | 4138,0                      | 5,56             |
| <b>Apr/2021</b> | 213045,2                       | 42609,0                                 | 3792,2                      | 5,27             |
| <b>May/2021</b> | 231235,9                       | 46247,2                                 | 4116,0                      | 5,53             |
| <b>Jun/2021</b> | 200390,7                       | 40078,1                                 | 3567,0                      | 4,95             |

|                 |          |         |        |      |
|-----------------|----------|---------|--------|------|
| <b>Jul/2021</b> | 234481,6 | 46896,3 | 4173,8 | 5,61 |
| <b>Aug/2021</b> | 156951,3 | 31390,3 | 2793,7 | 3,76 |
| <b>Sep/2021</b> | 228234,3 | 45646,9 | 4062,6 | 5,64 |
| <b>Oct/2021</b> | 231481,5 | 46296,3 | 4120,4 | 5,54 |
| <b>Nov/2021</b> | 236339,4 | 47267,9 | 4206,8 | 5,84 |
| <b>Dec/2021</b> | 215317,2 | 43063,4 | 3832,6 | 5,15 |

## Annex B

In Annex B are presented the prices of the new burners through which were estimated the adaptations costs for the burners for blend ratios of 15% and 20%.

|                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |                                   |   |                    |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------|---|--------------------|
| <p>Quemador Weishaupt Monarch disociado modelo WKG40/2-A ZMH - 3LN de muy bajo NOx, Gas natural con regulación modulante, con rampa de baja presión 1½". Convertidor de frecuencia IP20 en cuadro electrico. Regulación de O2 en continuo. Integración en G.T.C. Modbus. Apto para TRD604 y UNE676-267 Anexos K.</p> <p>Marca: CSC</p> <p>Modelo: LM12</p> <p>Potencia bruta: 1,585.23 kW</p> <p>Consumo: kg/h</p> <p>Sobrepresión hogar: 4.00 mbar</p> <p>Combustible: Gas natural</p> <p>Cabeza: -</p> <p>Pletina: -</p> <p>Clapeta:</p> <p>Tensión:</p> <p>Frecuencia: Hz</p> <p>Presión en llave de corte: 300 mbar</p> <p>Con W-FM 200</p> <p>Terminal ABE montado en el quemador</p> <p>Quemador WKG40/2-A ZMH - 3LN</p> |                                   |   |                    |
| 55709                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          | WKG40/2-A ZMH-3LN 1 1/2" Quemador | 2 |                    |
| <b>Subtotal Quemador WKG40/2-A ZMH - 3LN</b>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |                                   |   | <b>70.171,50 €</b> |

Figure B. 1: New LM12 burner specifications.

Quemador Weishaupt Monarch disociado modelo WKG50/2-A ZMH - 3LN de muy bajo NOx, Gas natural con regulación modulante, con rampa de baja presión 2". Convertidor de frecuencia IP20 en cuadro eléctrico. Regulación de O2 en continuo. Integración en G.T.C. Modbus. Apto para TRD604 y UNE676-267 Anexos K.

Marca: CSC

Modelo: LM300

Potencia bruta: 3,977.27 kW

Consumo: kg/h

Sobrepresión hogar: 4.00 mbar

Combustible: Gas natural

Cabeza: -

Pletina: -

Clapeta:

Tensión:

Frecuencia: Hz

## OFERTA

**Oferta:**  
2022.10089.89827

**Data:**  
04/02/2022



**Versión:** 2v

**V/Ref:**

**Obra:** Quemadores - Caldeiras CSC

**A/A:** Engº Gonçalo Figueiredo / Amcor Flexibles Portugal Lda

**Página 14 de 16**

Presión en llave de corte: 300 mbar

Con W-FM 200

Terminal ABE montado en el quemador

Quemador WKG50/2-A ZMH - 3LN

55718 WKG50/2-A ZMH-3LN 2" Quemador

2

**Subtotal Quemador WKG50/2-A ZMH - 3LN**

**82.221,00 €**

Figure B. 2: New LM300 burner specifications.



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