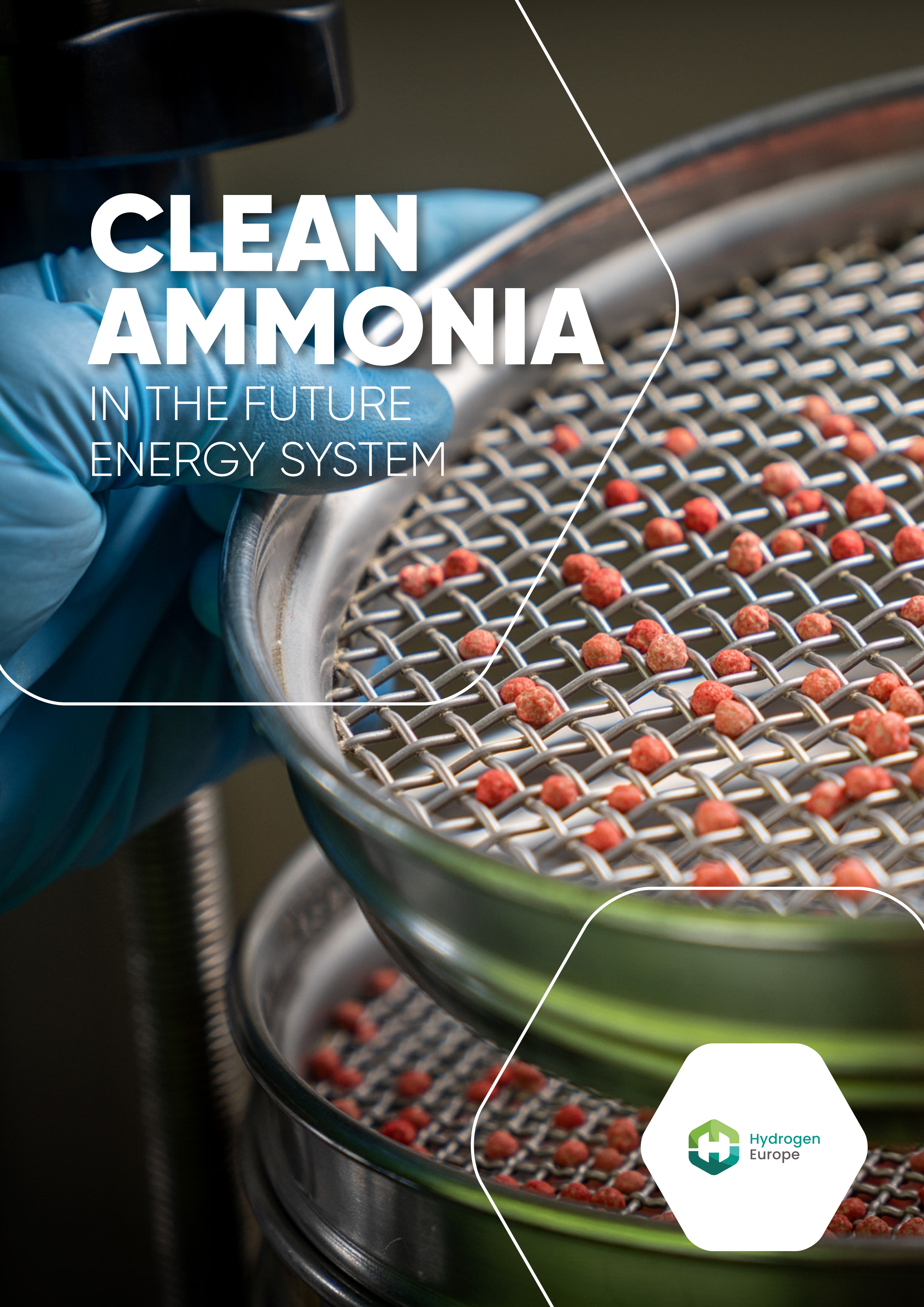
CLEAN AMMONIA

IN THE FUTURE ENERGY SYSTEM



Hydrogen Europe

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March 2023

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01 Introduction

Hydrogen Europe is the leading European hydrogen and fuel cell association that promotes clean and low carbon hydrogen as the enabler of a zero-emission society. It currently represents more than 400 entities, including 328 industry members, 30 EU regions and 35 EU national associations. Its member companies are of all sizes and represent the entire hydrogen value chain, from production to transport, distribution and final end-use of hydrogen. As such, Hydrogen Europe represents the common interests shared by stakeholders of the hydrogen industry in the EU and plays a crucial role in promoting best practices, providing market intelligence and formulating effective public policies. The association partners with the European Commission in the innovation program Clean Hydrogen Partnership supporting R&I activities targeting the development of hydrogen technologies. Thanks to its broad and various membership, Hydrogen Europe has a full overview of the industrial and market landscape and a direct, privileged connection with the hydrogen and fuel cell industry.

Hydrogen Europe supports low- or zero-carbon hydrogen production pathways to enable a zero-emission society and promotes hydrogen technologies as a way to achieve the climate targets of the Paris Agreement. It fully adheres to the European Union's target of carbon neutrality by 2050 and supports the European Commission's objectives to develop and integrate more renewable energy sources into the European energy mix.

The energetic and economic crisis currently felt at a global level has made clear how important it is to diversify our sources of energy and has opened an opportunity for green and sustainable solutions to come forward. As the EU sets out ambitious targets to import 10 million tons (Mt) of green hydrogen and its derivatives by 2030, ammonia steps up as one of the most attractive hydrogen carriers to help achieve these goals. While the current production of ammonia is quite carbon-intensive and very much reliant on natural gas, it is also a widely traded commodity for which significant transportation infrastructure is already in place. Moreover, as the EU discusses concrete targets for the use of renewable hydrogen in industry, increasing pressure is felt by the ammonia sector to transition into greener production methods.

The following publication contains a techno-economic analysis of alternative and cleaner pathways for ammonia production, looking both at carbon capture technology and renewable energy-based electrolysis. The analysis is based on a comparative levelized cost of product approach, with natural gas steam methane reforming serving as a benchmark for the counterfactual scenario. It also analyses different emerging applications for ammonia, namely its use as a fuel in the maritime sector and for power generation. The purpose of this analysis is to assess the viability of decarbonising the sector using different technologies and to identify boundary conditions for them to become economically feasible.

The results of this report should not be seen as a recommendation of the best available solutions but rather as an attempt to provide deeper insight into the technologies included in the analysis. It also remains a representation of Hydrogen Europe's Secretariat views, which does not necessarily represent the view of all Hydrogen Europe Members.

02

Executive summary

Ammonia is already a strategically important global commodity. While it has a range of various applications in the chemical industry, refrigeration, mining, pharmaceuticals, etc., it is its use for the production of synthetic nitrogen fertilisers which makes it a key element in global food security, supporting food production for around half of the global population.

In the EU-27, there are currently 32 ammonia facilities in operation. Combined, at full capacity, EU-27 plants can produce around 17.7 Mt of ammonia per year. Germany and the Netherlands have the largest ammonia production capacities within the EU-27 of around 3 Mt each per year. Poland is next with over 2.8 Mt of capacity per year.

The ammonia industry is inextricably linked to the hydrogen industry. With around 2.5 Mt of hydrogen being used as feedstock to produce ammonia per year, it accounts for almost a third of all current hydrogen consumption in Europe. As most of the hydrogen is produced on-site, the ammonia industry is both the second largest producer and consumer of hydrogen, after oil refining. Yet – as refining of crude oil might diminish in importance as the world moves towards decarbonisation, the role of ammonia is likely only going to increase.

Its importance and wide range of applications aside, the sector is currently responsible for a significant amount of greenhouse gas (GHG) emissions. Globally, with 185 Mt of ammonia production in 2020, the sector is responsible for around 500 Mt of $CO_{2\text{-eq}}$ emissions annually, representing over 1% of global GHG emissions. If methane leakage and other indirect emissions related to the supply of natural gas are taken into account, the total global GHG emissions would surpass the half Giga-tonne mark. A portion of those emissions is however captured and used again for urea synthesis.

While the EU's ammonia industry is already world leading, with the lowest average GHG emissions per tonne of ammonia produced, the average direct GHG emissions intensity of ammonia manufacturing installations is still close to 2 tCO2/tNH3 (compared to a global average of around 2.2). Most of the direct GHG emissions resulting from ammonia production are linked to the supply of hydrogen used as feedstock for the Haber-Bosch process. Currently, in Europe, hydrogen is overwhelmingly derived from natural gas via Steam Methane Reforming. **The use of renewable or low-carbon hydrogen, would lead to almost complete decarbonisation of the ammonia manufacturing industry.**

There are as many routes to reach that objective as there are ways to produce hydrogen sustainably. One of the pathways, offering an almost zero-emission solution, would be to supply renewable hydrogen as feedstock. Cost-wise however, it remains a significant challenge.

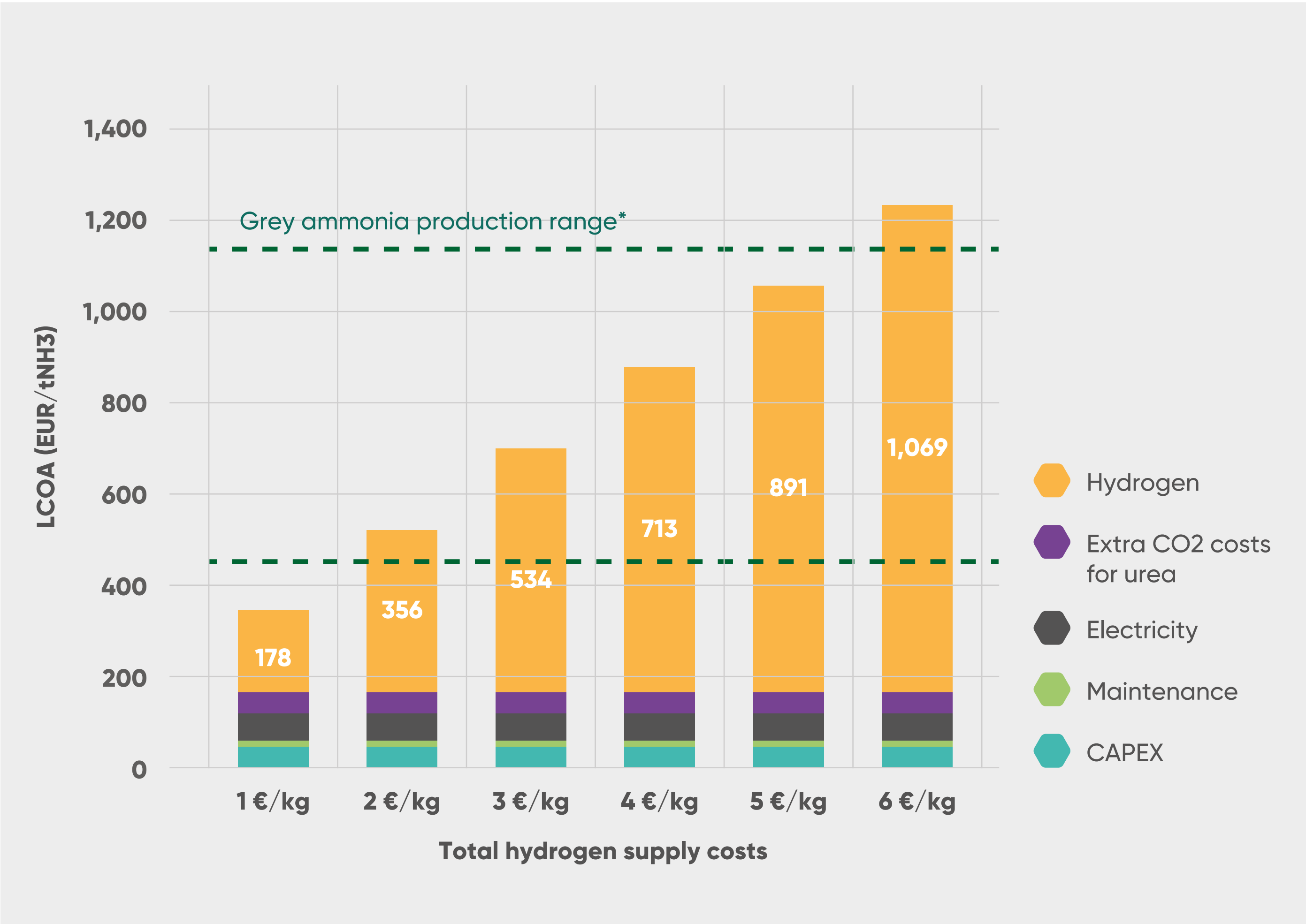
In fully electrified ammonia production, based on hydrogen produced via water electrolysis, the hydrogen supply costs would be, by far, the dominant cost item. At recent (December 2022) high natural gas prices in Europe (110 EUR/MWh) and CO2 emission costs (75 EUR/t) using low carbon or renewable electricity instead of natural gas for ammonia production would be profitable in the EU even at a relatively high hydrogen supply cost of 5.4 EUR/kg. However, with such high production costs, ammonia production in the EU would not be competitive with imported ammonia from low-cost gas regions. Furthermore, as natural gas prices are expected to drop, the pressure on renewable hydrogen supply costs will intensify.

With natural gas prices at 50 EUR/MWh (2025 price forecast by the IEA) the break-even point for renewable hydrogen supply cost would be at around 3.0 EUR/kg. If, however, the natural gas prices were to fall back to their historical level of around 20 EUR/MWh, the pressure for hydrogen supply costs would increase significantly, moving the hydrogen break-even point to around 1.6 EUR/t.

It should also be highlighted that the above break-even point values include all costs related to the hydrogen supply. Therefore, if hydrogen was to be produced off-site or imported and delivered via pipelines then all those additional costs would have to be covered as well. Similarly, for on-site production, grid connection fees as well as potential costs of RED II/III compliance would also have to be factored in, further increasing pressure on hydrogen production costs.

This also highlights the importance of not creating unnecessary regulatory burdens by introducing strict renewable energy additionality and temporal correlation requirements, which generate additional costs. For example, excluding renewable assets which benefited from any state

Figure 1: LCOA FOR GREEN AMMONIA DEPENDING ON RENEWABLE HYDROGEN SUPPLY COSTS.
Source: HYDROGEN EUROPE.



Note: Grey ammonia production range estimated for CO_2 cost of 75 EUR/t and natural gas cost range between 20 EUR/MWh and 110 EUR/MWh

aid support from the possibility of using them for renewable hydrogen production would significantly limit the chances of a fast build-up of renewable ammonia production – especially as most leading ammonia-producing countries in the EU are already facing a deficit of renewable energy potential.

Unnecessarily strict requirements with regard to temporal correlation would create a need for hydrogen storage. For an average ammonia plant (500 kt of ammonia capacity per year), an hourly temporal correlation requirement would create a storage requirement of close to 7,000 tonnes of hydrogen, increasing the cost of hydrogen by around 0.3 EUR/kg – further complicating the business case.

Another complication with a complete switch to renewable hydrogen for ammonia production might be the loss of a CO_2 source, which is currently often used for urea production. According to the IEA, **globally around 52% of CO_2 emissions from ammonia manufacturing are used directly to produce urea** (IEA, 2021). As the production of hydrogen via water electrolysis does not generate any direct CO_2 emissions, switching to this technology as the main source of hydrogen will therefore eliminate the supply of CO_2 needed for urea synthesis. If Direct Air Capture is used to replace the CO_2 previously supplied by SMR, the CO_2 cost would add 88-230 € per tonne of urea – i.e. 42-110% of its current market price. These are significant additional costs for the plant, which could well make urea production unprofitable and would therefore create an additional barrier to switching to renewable hydrogen. As an alternative, nitrate fertilisers do not contain any carbon and can therefore be produced instead of urea without the need for an additional CO2 source.

The blue ammonia pathway has its own challenges – mostly related to its perceived sustainability. Because the SMR process is heavy on flue gas emissions, which are not as easily captured as process emissions, if CCS was to be retrofitted in an existing SMR unit and applied only on the process CO2 stream, the resulting hydrogen (and ammonia) would not meet the low-carbon threshold established in the EU taxonomy for sustainable finance. On the other hand, if the ATR technology with CCS were used, the resulting hydrogen would be well below the EU taxonomy threshold. If natural gas from the Netherlands or Norway would be used instead of Russian gas, the LCA footprint of hydrogen could be below 1 tCO2/tH2 even if indirect emissions from the natural gas supply would be included.

We estimate that with costs of CO2 permanent storage at 30 EUR/tCO2, **the CO2 break-even price, using the ATR+CCS approach is around 51 EUR/tCO2** – i.e. below the current CO2 emission costs in the EU ETS.

As a result, overly restrictive additionality and temporal correlation burdens will create an incentive for CCS to become the preferred decarbonisation option for an integrated ammonia plant.

The importance of the policy framework goes far beyond this. The numerous recent policy initiatives from the European legislators, following the REPowerEU communication, provide a solid building block for the decarbonisation of the ammonia sector. However, the current policy initiatives focus primarily on the upstream part of the ammonia value chain – with the downstream part often neglected. Development of favourable policies for the value chain segments that will consume renewable ammonia, such as the maritime, the power sector and fertilisers segments, would go a long way in accelerating the energy transition of the sector. An example of such supporting measures would be a sub-target for use of a minimum percentage of e-fuels by 2030 in the maritime sector, coupled with a multiplier for use of e-fuels above the sub-target. The development of ammonia (and RFNBO in general) certification schemes, differentiating renewable and low-carbon ammonia from unabated fossil ammonia, must also be accelerated to create trust in product labelling.

If the regulatory framework and necessary support schemes are put in place, low carbon ammonia will provide opportunities for decarbonisation, going well beyond its current use in the fertilizer industry, with one of the most promising new applications being the use of ammonia as an energy carrier to facilitate international trade for renewable energy.

An expected increase in hydrogen demand and geographical imbalances related to access to abundant quantities and low-cost renewable energy will facilitate large-scale international trade for hydrogen and its derivatives. The importance of imports has been underpinned by the REPowerEU target to import into the European Union (EU) at least 10 Mt/y of renewable hydrogen annually by 2030.

There are of course many ways of importing renewable hydrogen, including pipelines, liquid organic hydrogen carriers, methanol and others. Ammonia offers however some significant advantages. For one, it is already a globally traded commodity with around 20 Mt traded annually, with around 17-18 Mt by ships. As a result, the logistics infrastructure needed for its efficient and safe handling is already largely in place. If ammonia were to become a dominant hydrogen carrier, this infrastructure would have to be expanded significantly, but to some extent, the existing LPG storage and transport infrastructure could also be relatively easily repurposed to handle ammonia as well – due to similar storage requirements. Existing LNG terminals could also be repurposed (partially or totally) to receive, store and handle ammonia. While ammonia is very toxic, protocols for its safe handling are already in place and the safety track record proves that ammonia shipments can be executed, in a safe way, at scale.

A key barrier is the cost of conversion of ammonia back to hydrogen. While there are some promising emerging technologies, including feedstock versatile membrane reactors[1], the only technology available at an industrial scale now would be thermal reforming, requiring around 52 GJ/tH2. As a result, unless a relatively low-cost renewable or waste heat source is available, the costs of ammonia cracking can form the largest portion of hydrogen delivery costs (excluding the costs of hydrogen itself) - drastically impacting the cost competitiveness of imported hydrogen.

Therefore, avoiding the dehydrogenation costs altogether by direct use of ammonia could, in many cases, be the key condition for ensuring the financial viability of importing renewable energy in the form of ammonia.

This is where the expected development of other potential new applications for ammonia will play a key role. The most promising new markets include the use of ammonia as a fuel for power generation and energy storage as well as the use of ammonia as an alternative fuel in the maritime sector.

In mobility applications, ammonia can both be cracked back into pure hydrogen that is then fed into fuel cells or used directly in certain high-temperature fuel cells or combustion engines. If the production of ammonia is carried out with zero CO2 emissions, that is, if renewable or low-carbon hydrogen is used as feedstock, it can become an attractive alternative fuel for hard-to-decarbonise sectors such as heavy-duty transport, as the burning of ammonia or its use in fuel cells does not generate any CO2 emissions as well.

Similarly, the power sector itself can also benefit from the application of ammonia. As the world moves away from fossil fuels into renewable energy sources, there is an increasing need for cost-efficient energy storage to manage the seasonality of wind and solar energy sources. In times of surplus, electricity is converted into hydrogen and afterwards into ammonia and stored, and in times of power deficit, it can be either cracked back into hydrogen for use in turbines or fuel cells or used directly as a fuel for certain power plants.

According to the IEA, the demand for ammonia from the new applications is set to be twice as high as the demand for its existing applications by 2050 (IEA, 2021). Considering an ammonia use in these promising applications in addition to existing ones, total ammonia demand could reach almost 600 Mt in 2050.

1 / https://www.h2site.eu/en/

03 Sector dynamics and decarbonisation needs

3.1. The ammonia molecule and its properties

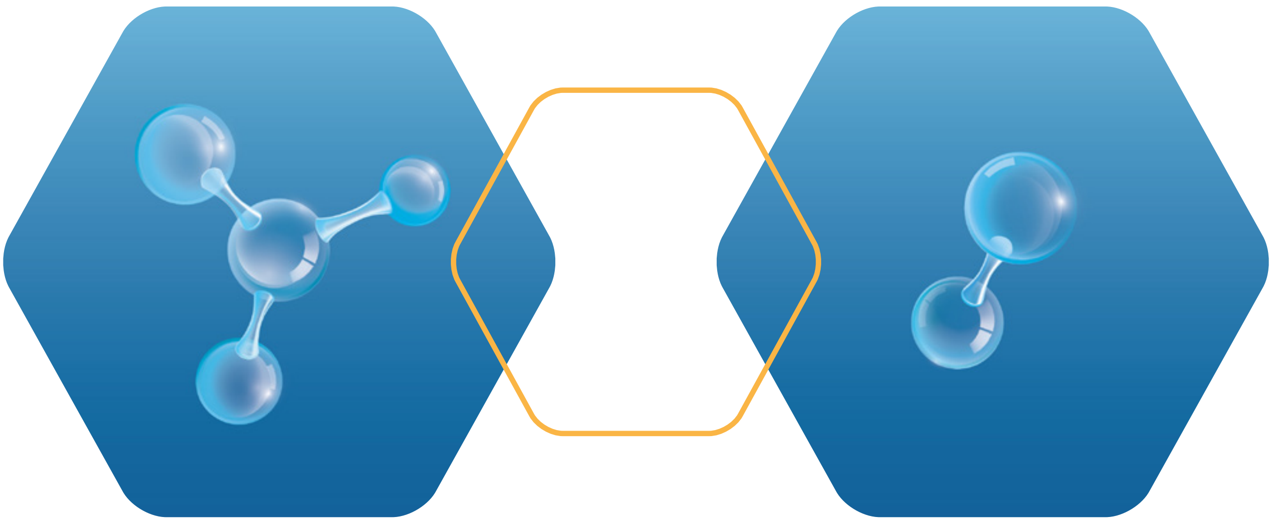
Ammonia is a molecular compound with a carbon-free chemical structure, NH3. Although it also exists naturally in organisms and the environment, ammonia is commonly produced artificially. In the environment, ammonia is part of the nitrogen cycle, where different nitrogen-containing molecules (e.g. N2, NH3, NO2) are converted from one to another, helping the ecosystem to be in balance and providing enough nitrogen in adequate form for organisms.

To produce ammonia artificially, molecular hydrogen (H2) and molecular nitrogen (N2) are commonly used as feedstock. In its final form, 1 kg of ammonia contains around 176 g of hydrogen and 824 g of nitrogen.

In standard conditions, ammonia is a gas. It can be, however, easily liquefied, requiring -33.4°C at atmospheric pressure or 7.5 bar pressure at 20°C. Ammonia has alkaline properties and is toxic and corrosive, which makes its handling require quite strict safety measures. In its gaseous form, ammonia rapidly dissipates into the atmosphere however complete dissipation may take enough time to generate a dangerous concentration in the site after the release. Even though colourless ammonia has a noticeable odour and its release is easily detectable, inhalation or contact with ammonia, even in low concentrations, can cause cough and irritation of the nose, throat, and skin, while high concentrations can cause serious burnings.

Table 1: BASIC PROPERTIES OF AMMONIA AND HYDROGEN.
Source: U.S. NATIONAL RESPONSE TEAM, H2 TOOLS, THE ENGINEERING TOOLBOX, TOPSOE.

	NH_3	H_2
Molar mass (g/mol)	17.03	2.02
Boiling point (°C)	-33.4	-252.9
Melting point (°C)	-77.8	-259.1
Density at 0° C, 1 atm (kg/m^3)	0.77	0.09
Higher Heating Value (HHV) (MJ/kg)	22.5	141.9
Lower Heating Value (LHV) (MJ/kg)	18.9	120.0
Energy density (liquid) (MJ/l)	12.7	8.5



3.2. Production and consumption of ammonia

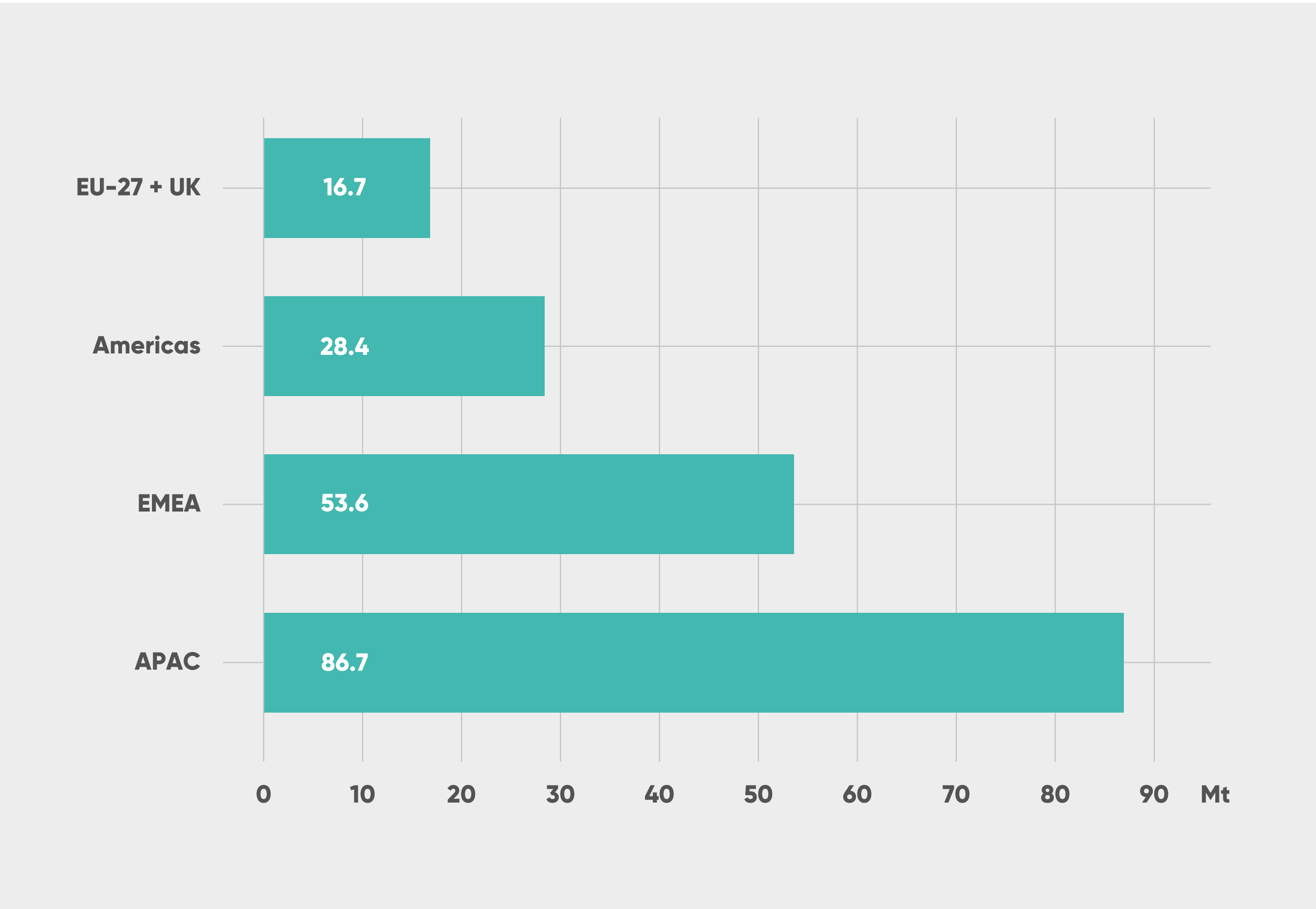
The chemical structure of the ammonia molecule is a building-block for numerous chemicals employed in wide range of applications, making ammonia a globally traded commodity with great value.

3.2.1. Global production

Global ammonia production has been increasing for four consecutive years, reaching 185 Mt in 2020 (IFA, 2021). Its production is heavily concentrated in the APAC region, with China being by far the largest producer. In 2020, almost 47% of the total ammonia produced, or over 86 Mt of ammonia, took place in the region, with China responsible for over 53 Mt. Another 29% (over 53 Mt) took place in the EMEA region, and around 15% (around 28 Mt) in the Americas.

In contrast to increasing global volumes, production in the EU-27 + UK has been declining for two consecutive years, recovering in 2020. In 2017, 17.6 Mt were produced in the EU-27 + UK, or around 10% of the global volume, whereas production in 2020 is estimated at 16.7 Mt, or about 9% of the total volume. In the same period, EU-27 ammonia imports increased, and decreased in 2020, when production slightly recovered. Apparent EU-27 + UK consumption[2] in 2020 represented over 19 Mt, roughly steady in comparison to the past few years (IFA, 2021).

Figure 2: GLOBAL PRODUCTION OF AMMONIA BY REGION IN 2020 (IN MILLION METRIC TONNES).
Source: (IFA, 2021).



2 / Consumption is estimated using apparent consumption, calculated summing production and imports, minus exports.

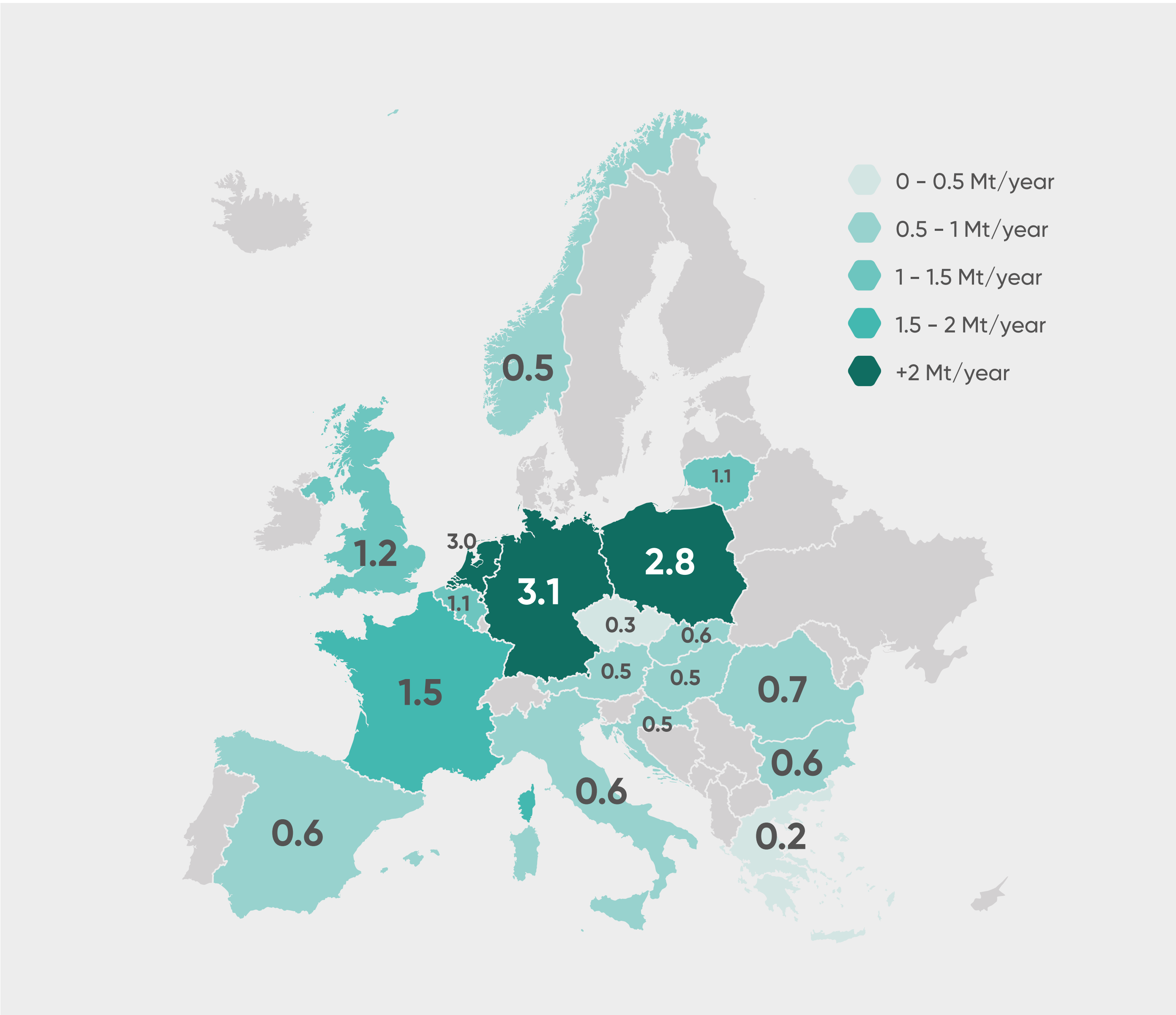
3.2.2. Production capacity in the European Union (EU-27)

In the EU-27, there are currently 32 ammonia facilities in operation. Combined, at full capacity, EU-27 plants can produce around 17.7 Mt of ammonia per year. Germany and the Netherlands have the largest ammonia production capacities within the EU-27, each with around 3 Mt per year. Poland is next with over 2.8 Mt of capacity per year.

3.2.3. Ammonia applications and consumption

Ammonia is used worldwide not only in the fertiliser sector but also as a feedstock in the manufacturing of commercial explosives, in the textile industry, in the chemical industry and in other minor applications such as in household cleaning products. In the fertiliser industry, ammonia is mostly used for the production of urea or other compounds such as

Figure 3: AMMONIA PRODUCTION CAPACITY IN THE EU-27, UK AND NO (IN MILLION METRIC TONNES).
Source: HYDROGEN EUROPE.



ammonium nitrate, ammonium sulphate and ammonium phosphates. To a lesser extent, liquefied ammonia is also applied directly to the soil, mostly in North America.

According to the IEA (IEA, 2021), out of the total ammonia demand from all end-uses in the world, including ammonia for nitric acid and ammonium nitrate production, around 70% is used in nitrogen-based fertilisers, of which 55% is for urea production and 2% is used directly in the soil. The remaining 30% of ammonia is used for industrial applications.

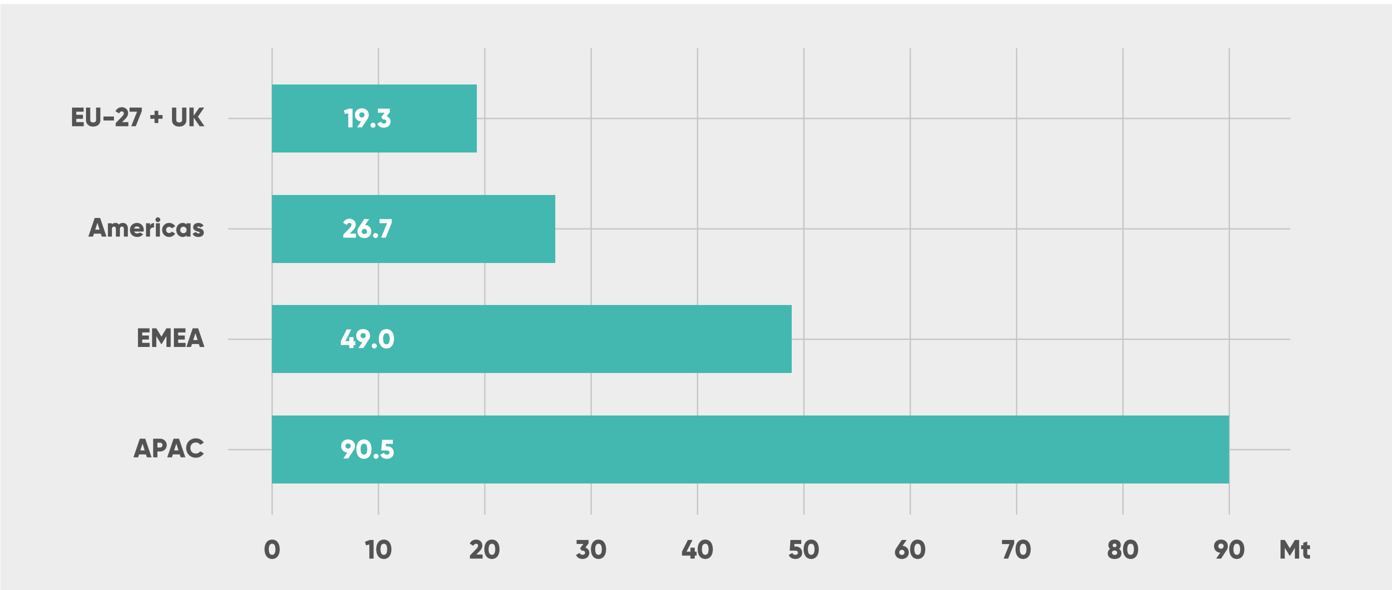
Urea fertilisers are indeed the most commonly used nitrogen-based fertilisers in the world. They present many advantages, including their rich nitrogen content, but also require a CO2 source when being manufactured. In fact, this CO2 is later released into the atmosphere once the fertiliser is applied to the soil. In Europe, nitrates are the preferred nitrogen-based fertiliser option.

As a chemical feedstock, ammonia is broadly used in nitrogen-based chemicals, in the nitriding of alloy sheets, as a carrier of atomic hydrogen for welding, as a coolant in refrigeration and air-conditioning technologies, as catalyst in the manufacturing of synthetic resins, as a neutralizer of acidic by-products in petroleum refining, as a preventor of coagulation of raw latex in the rubber industry, as feedstock in the Solvay process to commonly produce soda ash, in the Ostwald process to convert ammonia into nitric acid, and as a solvent in its liquid form.

In the production of commercial explosives (e.g. trinitrotoluene and nitro-glycerine), ammonia is used in the form of ammonium nitrate. In the textile industry, it is used to dye and scour cotton, wool and silk, and as input in the manufacturing of synthetic fibres, as nylon and rayon. In other applications, ammonia is even used in the production of antimicrobial drugs and ammonia hydroxide as a household cleaner.

Global apparent ammonia consumption matches global production and has therefore been increasing over the past decade, reaching 185 Mt in 2020 (IFA, 2021). Across the globe, it has been widely consumed in the APAC region, that held in 2020 around 49% of total consumption, or over 90 Mt. In the EMEA region, consumption was around 26.5%, or about 49 Mt, and another 14.5% was consumed in the Americas, or roughly 27 Mt. EU-27 + UK consumption accounted for almost 10.5% or over 19 Mt, remaining roughly steady in comparison to the past few years.

Figure 4: GLOBAL APPARENT CONSUMPTION OF AMMONIA BY REGION IN 2020[3].
Source: (IFA, 2021).



3 / The global consumption is estimated using apparent consumption, calculated using a region`s production plus imports minus exports.

3.2.4. A glimpse into future production and consumption of ammonia

Based on future projects for the commissioning of new ammonia production capacity, **IFA estimates that future global ammonia production capacity will reach around 237 Mt in 2025.** As is the case with current production capacities, the expected development of new ammonia production facilities is also heavily concentrated in the APAC region, where 47% of the future capacity is located. Of the remainder, about 30% are in the EMEA region, almost 15% in the Americas, and around 8% in the EU-27 + UK (IFA, 2021).

As ammonia has consolidated its role in the fertiliser industry as essential feedstock, future consumption is expected to remain linked to fertilisers demand, which is, in turn, expected to increase as population size continues to grow (UN, 2019), requiring more fertilisers to grow crops to satisfy global demand for food[4]. Similarly, ammonia demand for industrial applications should also increase as its role as feedstock remains steady and industrialization intensifies across the world (UNIDO, 2021). As a result, according to IEA, in 2050 ammonia demand for existing applications should surpass 200 Mt (IEA, 2021).

Apart from its role in existing applications, ammonia has also been quoted as a renewable energy carrier and as a maritime transportation fuel.

Ammonia is regarded as an advantageous energy carrier as it contains 17.6 wt% of hydrogen, and when liquefied at around -33°C, has a relatively high volumetric energy density of 12.7 MJ/l, in comparison to 8.5 MJ/l of hydrogen, liquefied at around -250°C, making it also easier to handle, transport and store. Renewable energy carriers that show little energy loss from transportation, especially over long distances, have great potential in supporting the decarbonisation of the world energy system, as the trade of renewable energy across the globe will have to intensify due to natural geographical imbalances. Thus, ammonia can be specifically used as a hydrogen energy carrier, facilitating hydrogen exports to countries with few renewable energy resources. Although the high toxicity of ammonia poses some challenges to the safe handling of the substance, significant experience and standardisation is already available.

In mobility applications, ammonia can both be cracked back into pure hydrogen that is then fed into fuel cells or used directly in certain high-temperature fuel cells or combustion engines. If the production of ammonia is carried out with zero CO2 emissions, that is, either with the use of renewable hydrogen or carbon capture and storage technology, it can become an attractive alternative for hard-to-decarbonise sectors such as heavy-duty transport, as the burning of ammonia or its use in fuel cells does not generate any CO2 emissions as well.

Similarly, the power sector itself can also benefit from the application of ammonia. As the world moves away from fossil fuels into renewable energy sources, there is an increasing need for cost-efficient energy storage to account for the seasonality of wind and solar energy sources. In times of surplus, electricity is converted into hydrogen and afterwards into ammonia and stored, and in times of power deficit, it can be either cracked back into hydrogen for use in turbines or fuel cells or used directly as a fuel for certain power plants.

According to the IEA, the demand for ammonia from the new applications is set to be twice as high as the demand for its existing applications by 2050 (IEA, 2021). Considering an ammonia takeover in these promising applications in addition to existing ones, total ammonia demand could reach almost 600 Mt in 2050.

4 / Roberts (2009) estimate that 40-60% of the global food is produced using fertilisers.

3.3. Trade & Infrastructure

Global trade of ammonia has been geographically broad and relatively steady over the years, reaching in 2019 a total value of around EUR 5.6 billion (HARVARD CID, 2019). This is estimated to be equivalent to almost 20 Mt traded in 2019 (IFA, 2021), or around 10% of the global production, demonstrating how ammonia is already handled worldwide at a large scale.

Ammonia is typically transported around the world in the form of anhydrous ammonia, in its pure form containing no water, or, alternatively, as an ammonia solution, dissolved in water, usually with 24.5% content. Anhydrous ammonia is normally liquified, which requires compression to around 7 times atmospheric pressure or chilling to around -33°C. At this state, the energy density is about 12.7 MJ/l[5].

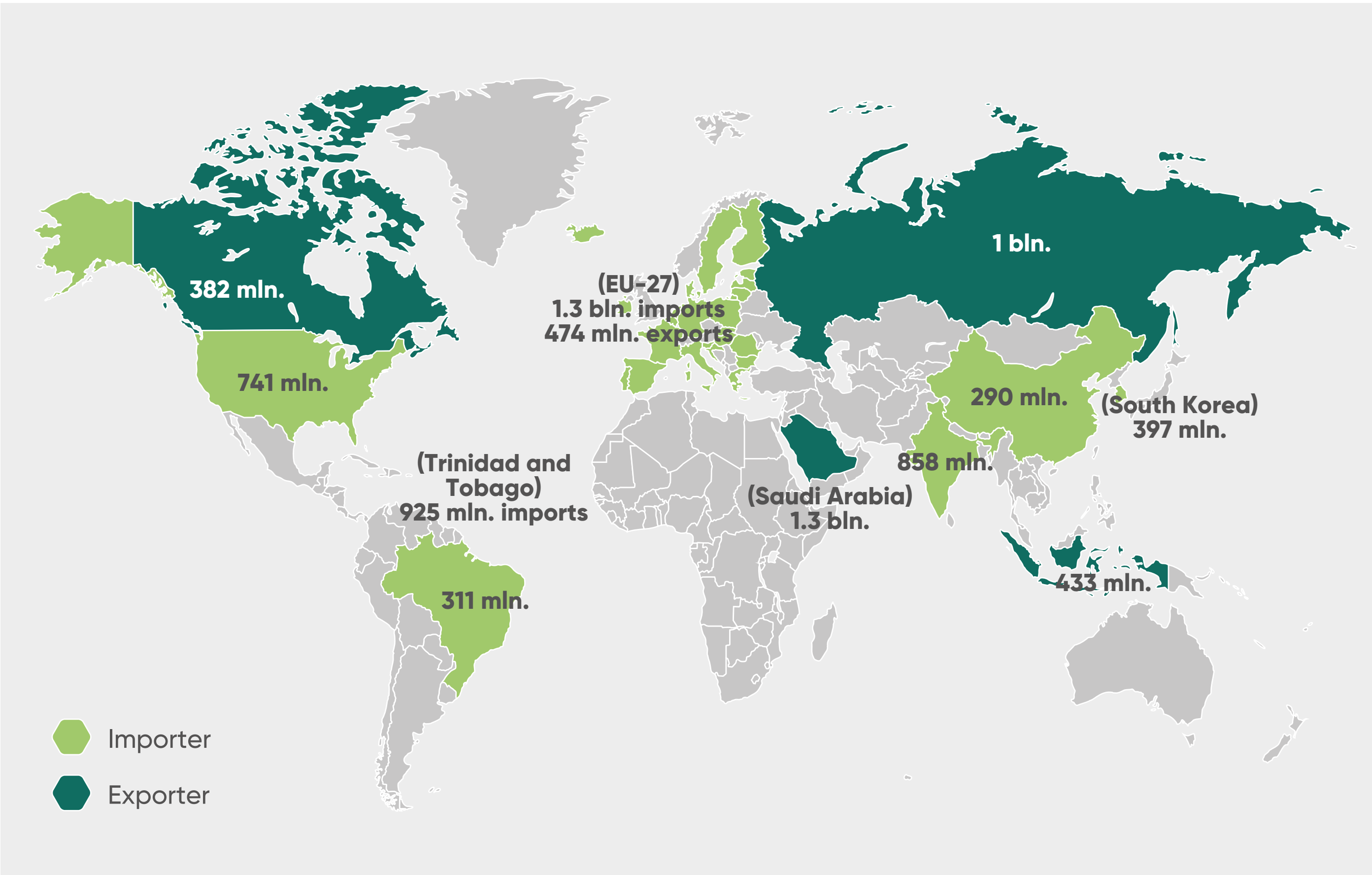
3.3.1. Main exporters

The five largest exporters of anhydrous ammonia on a country-level basis held together almost 70% of the entire export value in 2019. Saudi Arabia leads with almost 22%, followed by Russia with 18%, Trinidad and Tobago 15.5%, and Indonesia and Canada represent each less than 10%. EU-27 exports of ammonia together account for 8% of the total global ammonia export value in 2019, placing it among the main exporters in the world. The EU-27 export share of ammonia has slightly decreased in comparison to the past year.

3.3.2. Main importers

The five largest importers of anhydrous ammonia on a country-level basis are concentrated in Asia and the Americas and together are responsible for 44% of the entire

Figure 5: GLOBAL TRADE OF AMMONIA BY COUNTRY IN 2019 (IN BILLION AND MILLION USD).
Source: (HARVARD CID, 2019).



5 / For reference, energy density of LNG is 21.6 MJ/l.

ammonia imports value in 2019. India leads with almost 15%, the US follows with almost 13%, and South Korea, Brazil and China follow, each with less than 10%. Imports from the EU-27 represent together 23%, the highest share of the total imports value in 2019, steady since the past year.

The global trade of ammonia has been facilitated due to well-established international shipping routes, a well-developed infrastructure across many countries, and established safety standards and regulations for its transportation and storage. Ammonia is typically transported via pipeline from the production plant to the storage facility near the port. However, production facilities are often already located at the ports, making transportation easier.

Around the world, there are roughly 150 ports with ammonia terminals, of which 44% are in the EMEA region. Another 32.5% are in the APAC region and almost 23.5% in the Americas (DNV, 2022). Specifically, in the EU-27, there are to date around 30 ammonia terminals in operation, of which one-third export ammonia, either in parallel with import operations or only exports. Ammonia is often stored in isothermal tanks (up to 30 000 t) and spherical pressure tanks (1,000 – 2,000 t) (TOPSOE; ALFA LAVAL; HAFNIA; VESTAS; SIEMENS GAMESA, 2020).

From the port to the destination, the shipping is then made by specific gas carriers, in standard semi-refrigerated or fully refrigerated steel containers that will carry the compressed liquefied ammonia. Fully refrigerated carriers carry liquefied ammonia at low temperatures and atmospheric pressure and are in high demand for an increased global trade of ammonia. Due to similar liquefaction properties to LPG, ammonia can be stored in the same tankers as LPG, and LPG tankers are well-suited to transport ammonia. Typically, such tankers have a capacity of up to 40,000 t. It is estimated that currently, around 200 LPG tankers in operation can transport ammonia (fully refrigerated) (Brown, 2019). However, there are additionally over 1,200 LPG tankers that could potentially become suitable to transport ammonia in the future (CLARKSONS, 2020). Furthermore, existing fleet of more than 600 LNG vessels as well as the existing LNG terminals could also be repurposed to receive, store and handle ammonia.

On land, ammonia is usually distributed in its liquified form by railway or trucks. In Europe, most of the ammonia transportation takes place by rail insulated tank cars. It is estimated that 1.5 Mt of ammonia is transported within Europe every year via rail (Fertilizers Europe, 2007). On road, ammonia is transported by road trailers in pressurised tanks. For long-range transportation on land, pipelines are the preferred method. As ammonia is transported in liquid form, typically the pipelines have a much smaller diameter compared to natural gas pipelines. In the US, there is a 5,000 km long ammonia pipeline backbone, connecting Louisiana to the Corn Belt region and Texas to Minnesota. Around 2 Mt of ammonia is transported every year through this pipeline (Papavinasam, 2014). In Europe, a 2,471 km long ammonia pipeline connects Russia and Ukraine. Every year, this pipeline can transport roughly over 3 Mt of ammonia from Tolyatti to Odessa (TOGLIATTIAZOT, 2022).

3.4. Ammonia and the energy transition

The ammonia sector has been a major contributor to global GHG emissions. It is estimated that for each tonne of ammonia, around 2-2.5 tonnes of CO2-eq are directly emitted on average in the world (EC, 2022), due to the high energy demand of around 30-50 GJ per tonne of ammonia produced and currently supplied overwhelmingly by fossil fuels combustion. However, the EU-27 averages around 1.7-2.0 tonnes of CO2-eq, and it averages 1.6 tonnes of CO2-eq among the 10% best performing (EC, 2021). Together, the EU27 and UK become responsible for around 28 Mt CO2 every year. Globally, the sector was responsible for around 500 Mt of CO2-eq, representing over 1% of the global GHG emissions in 2020.

If energy demand, capacity factors and fuel mixes remain the same, in the coming decades the existing ammonia facilities would emit between 4.4 GT of CO2 by 2040 and up to 15.5 GT of CO2 by 2070 in a business-as-usual scenario, depending on the lifetime of plants (IEA, 2021). This would represent a massive retardation of decarbonisation efforts in the short and medium-term.

Most of the direct GHG emissions resulting from ammonia production are linked to the supply of hydrogen used as feedstock for the Haber-Bosch process. Currently, overwhelmingly, hydrogen is derived from natural gas via Steam Methane Reforming (SMR) in Europe.

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04 The EU policy landscape

This chapter deals with the policy framework for ammonia production, from decarbonisation measures, such as emissions trading and targets, to certification and funding schemes. As part of the Fit for 55 Package, EU policymakers will aim to bring a whole range of energy and climate policies, including the EU ETS, in line with the EU's new climate targets and the Green Deal. Those changes will affect the ammonia sector. While the European Commission had published its package of legislative proposals in 2021, European institutions are now progressively finalizing it, with deals reached on emissions trading policy and one on its way for consumption targets and certification of renewable hydrogen and derivatives (foreseen in early 2023) at the time of writing.

4.1. Carbon pricing for ammonia production and addressing carbon leakage risk

4.1.1.Introduction to the EU Emissions Trading System, the EU's carbon market

The EU Emissions Trading System (ETS) was first launched in 2005. The system applies a decreasing cap on GHG emissions that industry, the power sector and aviation, are allowed to emit. This scheme is in operation in all EU countries, as well as Iceland, Liechtenstein, and Norway. Under the ETS, a limited amount of GHG that can be emitted is imposed on all sectors covered. Emission allowances are then traded as needed, depending on a given emitter's needs to cover his emissions. At the end of the reporting period, each installation's operator or airline must present enough emission allowances to cover its real emissions or face fines in case of failing to do so. The possibility of trading allowances ensures that emissions cuts occur in those sectors where it is less costly to do so. Carbon dioxide emissions stemming from the production of ammonia are covered by the EU ETS, meaning that ammonia producers must purchase and surrender EU Allowances (EUA, or carbon quotas) yearly to cover their emissions and comply with the law.

4.1.2. Current protection measures against carbon leakage risk under the EU ETS

In energy-intensive industries such as ammonia production, the EU ETS adds such costs to the production process that it has a material impact on the price of the final product. As a result, if no additional measures are taken, there is a risk that carbon leakage happens, i.e., an increase in imported ammonia that has not been taxed on CO2 emissions and is therefore cheaper. The main measure in place to prevent that is currently the **free allocation of emission allowances** to energy-intensive industries like steel or ammonia, limiting the risk of carbon leakage, yet affecting the price signal and decarbonisation incentive for eligible sectors. Free allocation will, however, be progressively phased out and replaced by a Carbon Border Adjustment Mechanism meant to tax CO2 emissions from imported products and thus avoid carbon leakage. The allocation of allowances is based on benchmarks that are set for each covered product specifically. For the period between 2021 and 2025, benchmarks are defined based on the performance[6] of the 10% most efficient installations covered

6 / Measured in GHG emissions per tonne of production of the concerned goods.

by the EU ETS producing the respective product in the years of 2016/2017 (in contrast with previous benchmarks, where performance from 2008/2009 was considered). For the upcoming period starting in 2026 until 2030 (under ETS Phase IV), production data (historical activity levels) will be based on years 2021/2022. On top of regular data updates, annual reduction rates (ARR) apply to benchmarks: a minimum 0.2% for low innovation sectors and a maximum 1.6% for high innovation sectors. The revision of the EU ETS will increase, as from 2026, both minimum and maximum threshold to 0.3% and to 2.5%, respectively.

The manufacture of fertilisers and nitrogen compounds is a sector deemed at risk of carbon leakage.[7] For that reason, ammonia is one of the products covered by free allowance eligibility and has its own product benchmark[8], which for the period 2021-2025 has been set at 1.570 tCO_2e/tNH_3. This means that all installations with an emission intensity of their ammonia below this benchmark will receive an excess of free allowances compared to the amount which needs to be surrendered. As a result, these installations will be able to sell them for additional revenues, while installations above this benchmark will have to compensate by purchasing additional allowances to cover their remaining emissions.

Under Article 10a(6) of the ETS Directive[9], **Member States are allowed to compensate the most electro-intensive sectors for increases in electricity costs as a result of the EU ETS, through national state aid schemes.** The EU ETS state aid guidelines for 2021-2030 set the framework for Member States to compensate their electricity-intensive industries deemed at risk of 'carbon leakage' for potentially increased electricity prices, caused by the need for power companies to buy emission allowances (so-called "indirect emission costs"). Those new Guidelines make compensation conditional upon additional decarbonisation efforts by the companies concerned, such as complying with the recommendations of their energy efficiency audit. The aid shall not exceed 75 % of the indirect emission costs. **Yet, in their new 2020 version applying in force since January 2021, production of ammonia is no longer covered , a decision opposed by the fertiliser industry (Fertilizers Europe, 2020). However, since hydrogen is covered**[10] under the EU ETS state aid guideline for 2021-2030, a producer using its own renewable hydrogen for ammonia production would be covered under the guidelines for its hydrogen production part.

7 / Commission Delegated Decision (EU) 2019/708.
8 / Commission Delegated Regulation (EU) 2019/331.
9 / Consolidated text: Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a system for greenhouse gas emission allowance trading within the Union and amending Council Directive 96/61/EC (Text with EEA relevance).
10 / Commission Communication, Guidelines on certain State aid measures in the context of the system for greenhouse gas emission allowance trading post 2021, September 2020.

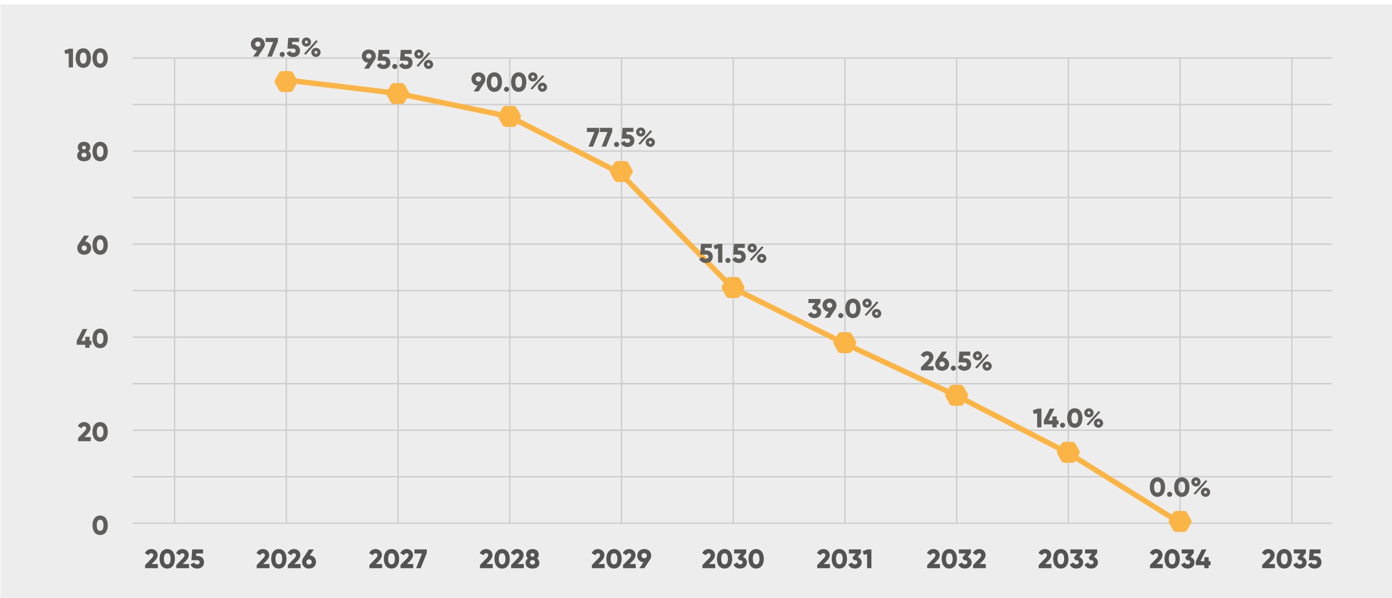
4.1.3. The EU's new carbon border tax: the Carbon Border Adjustment Mechanism (CBAM)

Considering the challenge of both the needed speedier decarbonisation and carbon leakage risk, the European Commission has proposed another measure aiming at intervening in the market of energy-intensive industries. The Carbon Border Adjustment Mechanism (CBAM) is a new policy put forward to gradually phase out and eventually replace free allowances under the EU ETS, the main measure protecting against carbon leakage risk until now. Free allowances are supposed to act against this risk for EU industries, yet they also reduce the incentive to decarbonise since they reduce the total cost of GHG emissions.

The CBAM aims to reflect the evolutions on the 'domestic' EU ETS market, in order to provide a level-playing field: CBAM certificates will need to be purchased by importers upon import of covered products. The price of CBAM certificates will reflect the price of ETS allowances on the same given week. Any carbon price (e.g., via an ETS of a third country) that was already paid in the producing country is deducted from the CBAM certificate. Importers in the EU ('Declarants') will have to pay for a CBAM certificate reflecting the weekly average ETS price for each tonne of embedded GHG emission in the products they imported over the year. The number of CBAM certificates to surrender (and therefore, the top-up on import price) will, like under the EU ETS, depend on emissions stemming from the covered activities. If actual emissions embedded in imported goods cannot be verified, then default values apply (at the level of 10% of most polluting EU production plants of the good). **The mechanism will start by covering cement, iron & steel, aluminium, fertilisers (which includes ammonia), electricity, and hydrogen.** The Commission considers the possible inclusion of other sectors under the scheme at a later stage. Likewise, the CBAM will cover indirect emissions of cement and fertilisers (which are not covered by State aid for indirect costs) in a first instance, and possibly of more products in the future.

The mechanism will have a transitional period starting from 1 October 2023 entailing emissions monitoring, and actual CBAM certificate surrendering (payments) will start in 2026. For the sectors covered by the CBAM, free allocations would be progressively phased out – as the CBAM is phased in – by the application of a 'CBAM factor' to those sectors' free allowances, until they are phased out: 97,5% in 2026; 95% in 2027; 90% in 2028; 77,5% in 2029; 51,5% in 2030; 39% in 2031; 26,5% in 2032; 14% in 2033; 0% in 2034. The application of this gradually decreasing CBAM factor would accelerate the decrease in free allowance allocation for the targeted sectors and would lead to the end of free allowances for those by 2034, a year earlier than the Commission's and Council's plan, yet two years later than that of the European Parliament.

Figure 6: FREE ALLOWANCES PHASE-OUT FOR COMMODITIES COVERED BY THE CBAM.
Source: HYDROGEN EUROPE.



In theory, the measure aims to address the displacement of GHG emissions of energy-intensive industries due to the introduction of climate policies, i.e. "carbon leakage". In practice, however, there are multiple challenges induced by the new regulation. The phase-out of free allowances has also been introduced to make sure the industry is not being "double-protected" both by free allocation of allowances and carbon taxes applied to imported goods. The consequence of the phase-out of free allowances is that, while CBAM will protect EU ammonia producers from extra-EU competition on the internal market, **it could still result in higher ammonia prices in the EU,** as long as low-carbon or renewable ammonia production remains expensive. Without any adequate compensation mechanism, **the phase-out of free allowances could negatively impact the cost competitiveness of EU ammonia or fertilisers industries producing predominantly for export.**

4.1.4. The inclusion of the maritime sector under the EU ETS

Under the revised EU ETS Directive, EU institutions agreed to include emissions from the maritime sector under the original ETS (i.e., ETS I; different from the new, separate 'ETS II' for emissions from road transport and buildings). Emissions considered are those of carbon dioxide (CO2), nitrous oxides (N2O) and methane (CH4) under the scheme, while amending consistently the MRV regulation. As of 2024, a 3-year phase in period would start, with emission coverage for the sector rising gradually, achieving 100% of emissions for the year 2026. The liable entity or person would be the shipowner or the person or organisation with the responsibility of the ship's operation. The maritime sector would not be eligible to free allowances under the ETS.

In terms of coverage, the Commission focuses on large ships (above 5,000 gross tonnage), accounting for 90% of CO2 emissions and in line with the existing scope of the MRV regulation[11]. This scope de facto excludes smaller maritime vessels and inland navigation from the ETS scope. Indeed, their emissions remain covered solely by the Effort Sharing Regulation's (ESR) national targets and are excluded from emissions trading. Yet, emissions of small general cargo and offshore vessels (between 400 and 5,000 gross tonnage) will be included in the MRV regulation as from 2025, possibly in view of covering them under the ETS after a review in 2026. There will also be a review clause on the potential inclusion of other small vessels in the MRV at the end of 2024.

The ETS scheme will cover emissions from intra-EU traffic, emissions at berth at an EU port, as well as 50% of the emissions from ships, either travelling from a non-EU port to an EU port or from an EU port to a non-EU one. The remaining 50% would have to be covered by the other relevant country's carbon pricing policy with an IMO-level solution. This is combined with a review clause; in case such IMO solution was not found.

In the context of the maritime sector coverage under emissions trading, the European Parliament had proposed the establishment of an Ocean Fund. This plan was rejected, yet, is to be replaced by specific calls for maritime under the Innovation Fund financed by 20 million allowances stemming from maritime sector auctioning. This would not prevent the sector from taking part in other calls under the Fund. The calls dedicated to the maritime sector wouldfinance, among others, the **deployment of "sustainable alternative fuels, such as hydrogenand ammonia that are produced from renewable energy."**[12]

Both the decarbonisation incentive implied by the coverage of the maritime sector in the ETS as well as the mentioned dedicated calls could represent significant opportunities for the development of ammonia as a fuel to decarbonise the sector.

11 / Regulation (EU) 2015/757 of the European Parliament and of the Council of 29 April 2015 on the monitoring, reporting and verification of carbon dioxide emissions from maritime transport, and amending Directive 2009/16/EC.
12 / 4-column document on the revision of the EU ETS Directive, 04 December 2022.

4.2. Incentives to foster green ammonia consumption

4.2.1. Definitions and certification

In its current (second) version, the Renewable Energy Directive (known as RED or RED II) provides a definition for hydrogen and hydrogen derivatives used as transport fuels. There, 'renewable liquid and gaseous transport fuels of non-biological origin' (RFNBO) are defined as *'liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass.'* This current regulatory framework sets additionality and temporal and geographical correlation requirements on the renewable electricity used for the production of the fuel and a greenhouse gas emission saving requirement of 70% relative to a fossil fuel comparator of 94 gCO2e/MJ. Those requirements would therefore apply to renewable ammonia – if used as fuel for transport applications. However, the RED revision is to expand the scope of RFNBO to uses beyond only the transport sector.

The two draft Delegated Acts, supplementing the RED II and to be published for final scrutiny by the European Parliament and Council in the coming weeks are to lay down additionality and temporal and geographical correlation criteria, as well as GHG emission saving requirements, respectively. The spirit would be to avoid potential increased GHG emissions due to increased power consumption for the purpose of producing renewable hydrogen and ensure RFNBO consumption effectively leads to decarbonisation.

With this objective in mind, the **first delegated act imposes an additionality criteria** of RES capacity used to power electrolysers. When the electrolyser is sourced directly from a RES installation, this RES installation will indeed have to have come into operation not earlier than a 36-month period before the electrolyser has come into operation itself. This would not apply during the transitional phase (until end of 2027). The additionality requirement does not apply if the electrolyser is connected to a power grid with a renewable energy share above 90% or if the grid carbon intensity is below 18 gCO2e/MJ.

Temporal correlation must also be proven, i.e., showing on an hourly basis that the electrolyser was strictly sourced by RES power. Before 2030, this can be proven on a monthly basis instead. Yet, it will need to be hourly if the RES plant is receiving state-aid support that is not CAPEX- based. What's more, no temporal correlation has to be proven if electricity prices are low (e.g. =<20 EUR/MWh) or if day-ahead market prices are below 0.36 times the price of an allowance to emit one tonne of CO2.

Geographical correlation, which is fully applicable, including during the transitional phase until 2027, means that 1) RES installation and electrolyser shall be in the same bidding zone at the time of commissioning, 2) neighbouring bidding zone where Day-ahead electricity prices for the same hour are equal or higher than in the bidding zone where the electrolyser is located is allowed, and 3) the RES plant is in an offshore bidding zone adjacent to the bidding zone where the ELY plant is located.

Finally, grandfathering is granted to installations commissioned before 1 January 2027; both for the 36-month and state-aid rules, meaning that the RES plant can receive CAPEX support.

The second delegated act, looking at GHG emission savings, sets a fossil fuel comparator at 94 gCO2e/MJ to calculate the required 70% reduction, meaning the GHG footprint threshold for hydrogen is 3.38 tCO2/tH2. Yet, this is before all other emissions, therefore meaning that the threshold is de facto lower. Although emissions from hydrogen compression do not need to be taken into account, emissions from electricity used for liquefaction do. Further emissions from fuel transportation to the refuelling station need to be included as well, lowering the threshold for hydrogen production even further.

In parallel, the revision of RED II (future RED III) is underway, as part of the Fit for 55 Package. One of the proposed amendments **is extending additionality and temporal and geographical correlation criteria to all other uses of hydrogen and its derivatives, beyond their use as transport fuels.** What this means for ammonia is that not only ammonia used in shipping, for instance, would be covered by additionality, but green ammonia used as a fertiliser or chemical feedstock will be too.

4.2.2. The RFNBO target for industry under the recast Renewable Energy Directive (RED)

Under the revision of the Renewable Energy Directive (RED), **the European Commission proposed a new binding target of 50% for renewable fuels of non-biological origin (RFNBO) consumption out of total hydrogen consumption, whether as feedstock or fuel[13], in industry[14].** As one of the main consuming sectors of hydrogen besides refineries, **ammonia production will be significantly impacted by this new provision.**

In essence, this target means achieving at least half of the total hydrogen consumption by 2030 with renewable hydrogen. It will induce a significant effort from the ammonia industry to replace its hydrogen consumption – generally based on steam methane reforming – with renewable hydrogen. This is despite the expectation that other sectors will start consuming renewable hydrogen by then – beyond the two formerly mentioned – such as steel, which could indirectly help the ammonia sector, by making the target more reachable. It should be noted, though, at equal hydrogen quantity levels and other all things being equal, it will be the switch of an ammonia plant from SMR-based hydrogen to renewable hydrogen consumption that will have the biggest impact in bringing the RFNBO consumption level closer to the target. Indeed, in the case of the switch from an existing hydrogen consumption to renewable hydrogen consumption (e.g., for green ammonia production), the nominator (renewable hydrogen consumption) would increase, and the denominator (total hydrogen consumption) would remain the same, bringing the renewable share closer to the 50% target. In the case of a new hydrogen consumption sourced from renewables (e.g., for green steel production), *both* the nominator and denominator increase by the same amount, therefore bringing the renewable share closer to the 50% target in a more moderate manner. Besides, it should also be noted that hydrogen used as intermediate products for the production of conventional transport fuels (essentially, hydrogen used as a reactant to de-sulphurise crude oil in refineries) is excluded from this target scope, as it is covered under another RFNBO target (for transport) under the RED revision proposal.

The obligated parties to the target are the Member States, who will pass on the obligation to the industry for them to comply. With the emerging status of the hydrogen sector and the foreseen leap in consumption for the coming years, the consumption volume of renewable hydrogen that will be required to comply is uncertain to an extent, considering new potential consumption from sectors that do not consume hydrogen today. This will also significantly vary between countries. Countries' capacities to supply renewable energy sources for renewable hydrogen production will also affect their ability to comply with this target. In Poland, for instance, this would mean consuming 0.15Mt of renewable hydrogen per year in 2030, requiring about 13 TWh of renewable power per year. Poland would need to deploy 61% of additional RES production capacity compared to its current one, for the mere purpose of supplying this demand.[15]

In the context of the 50% target, the CBAM can be an important tool to help prevent carbon leakage. Indeed, the target as such could possibly foster circumvention practices by end consumers, such as the import of additional, more carbon-intensive ammonia volumes from other countries not subject to stringent targets and carbon pricing policy. This could threaten domestic production in the EU. **To prevent this, it is essential that ammonia is included under CBAM,** i.e., that a price is applied to carbon-intensity of ammonia imports, as proposed by the European Commission. It should be clear however, that CBAM alone may not be enough to fully safeguard the European ammonia industry – especially against competition from low-cost natural gas regions.

The REPowerEU Plan, published on 18 May 2022, changes the context regarding the required transition away from fossil fuels. Following the Russian aggression against Ukraine, the plan aims to swiftly phase out fossil fuel supply (not least natural gas) of Russian origin. One of the key objectives of this plan is to increase renewable

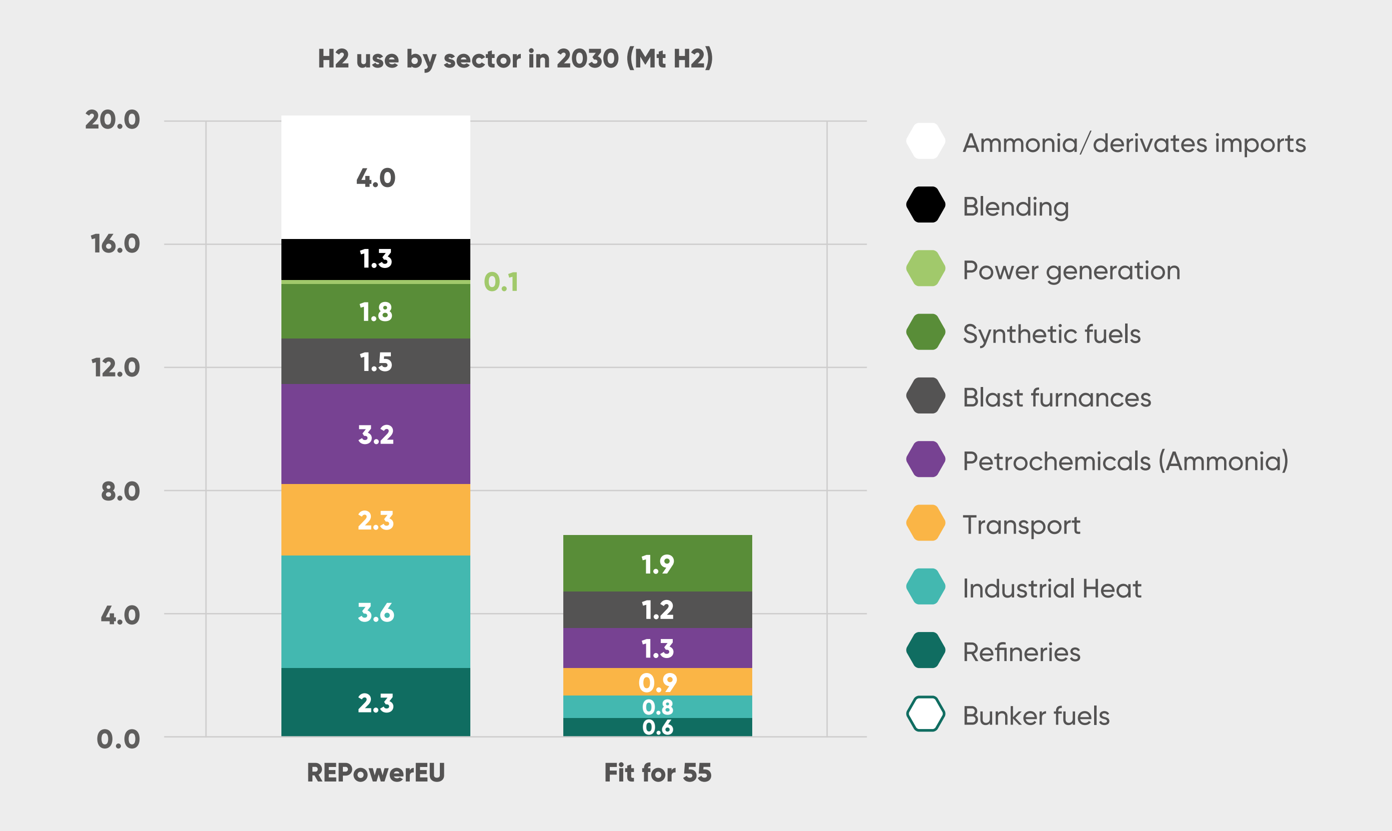
13 / Feedstock referred to as "non-energy uses" and fuel as "energy uses".
14 / "'industry' means companies and products that fall sections B, C, F and J, division (63) of the statistical classification of economic activities (NACE REV.2)," which includes the "Manufacture of chemicals and chemical products" and therefore the production of ammonia.
15 / Hydrogen Europe estimations.

hydrogen consumption to 20 Mt per year by 2030, up from 5.6 Mt foreseen under the Fit for 55 Package.

According to the Plan (in an attached Staff Working Document[16]), RFNBOs could have a 78% share in hydrogen consumed by the industry. **The Commission, therefore, calls on the co-legislators to increase the industry RFNBO target in the ongoing RED revision to 75%** (from the proposed 50% as part of the Fit For 55 package). Considering the ongoing interinstitutional negotiations (trilogues) between the Council and the European Parliament on the feasibility of achieving the previously proposed 50% target at the Member State level without including low carbon hydrogen, pushing through the proposed increase to 75% will be a challenge. In the latest round of negotiations on RED, the compromise retained was a target level of 42% instead.

In the EU, the current demand for hydrogen in the ammonia sector is 2.5 Mt (Hydrogen Europe, 2022). Depending on whether the 'petrochemicals' (3.2 MtH2 foreseen to be used there, according to the figure above) refers strictly to use of H2 for ammonia production or further uses, and depending on the allocation of the 4 MtH2 from 'ammonia/derivatives imports,' the Commission would seemingly table on a total replacement of grey hydrogen supply for ammonia production with renewable hydrogen by 2030, should demand remain more or less stable.

Figure 7: HYDROGEN USE BY SECTOR IN 2030.
Source: EC, COMMISSION STAFF WORKING DOCUMENT IMPLEMENTING THE REPOWER EU ACTION PLAN: INVESTMENT NEEDS, HYDROGEN ACCELERATOR AND ACHIEVING THE BIO-METHANE TARGETS.



16 / Commission Staff Working Document Implementing the REPower EU Action Plan: Investment Needs, Hydrogen Accelerator and Achieving the Bio-Methane Targets, 2022 (p. 27).

4.2.3. FuelEU Maritime

The FuelEU Maritime regulation (FEUM) is a key element of the Fit-for-55 legislative package, put forward by the European Commission with the aim of reducing GHG emissions from the maritime sector. In it the EC has proposed a goal-based GHG intensity target, requiring ship operators calling at EU ports to reduce the lifecycle GHG footprint of the energy used onboard ships. The targets proposed by the EC would start with 2% GHG intensity reduction in 2025, gradually increasing up to 75% in 2050.

As the penalties for non-compliance are relatively high (equivalent of 2,400 EUR/t of marine fuel) the FEUM would create a market for low-carbon solutions. Assuming the target would be met with zero-emission solutions only, and given the current carbon intensity of the shipping sector, the expected CO2 reduction would require the introduction of 69 TJ of alternative fuels by 2030 and 957 TJ by 2050.

Unfortunately, as the EC has not proposed any specific sub-targets for RFNBOs and as the targets until 2040 are relatively unambitious, there is a significant risk that, at least in the next decade, there will not be sufficiently strong RFNBO demand.

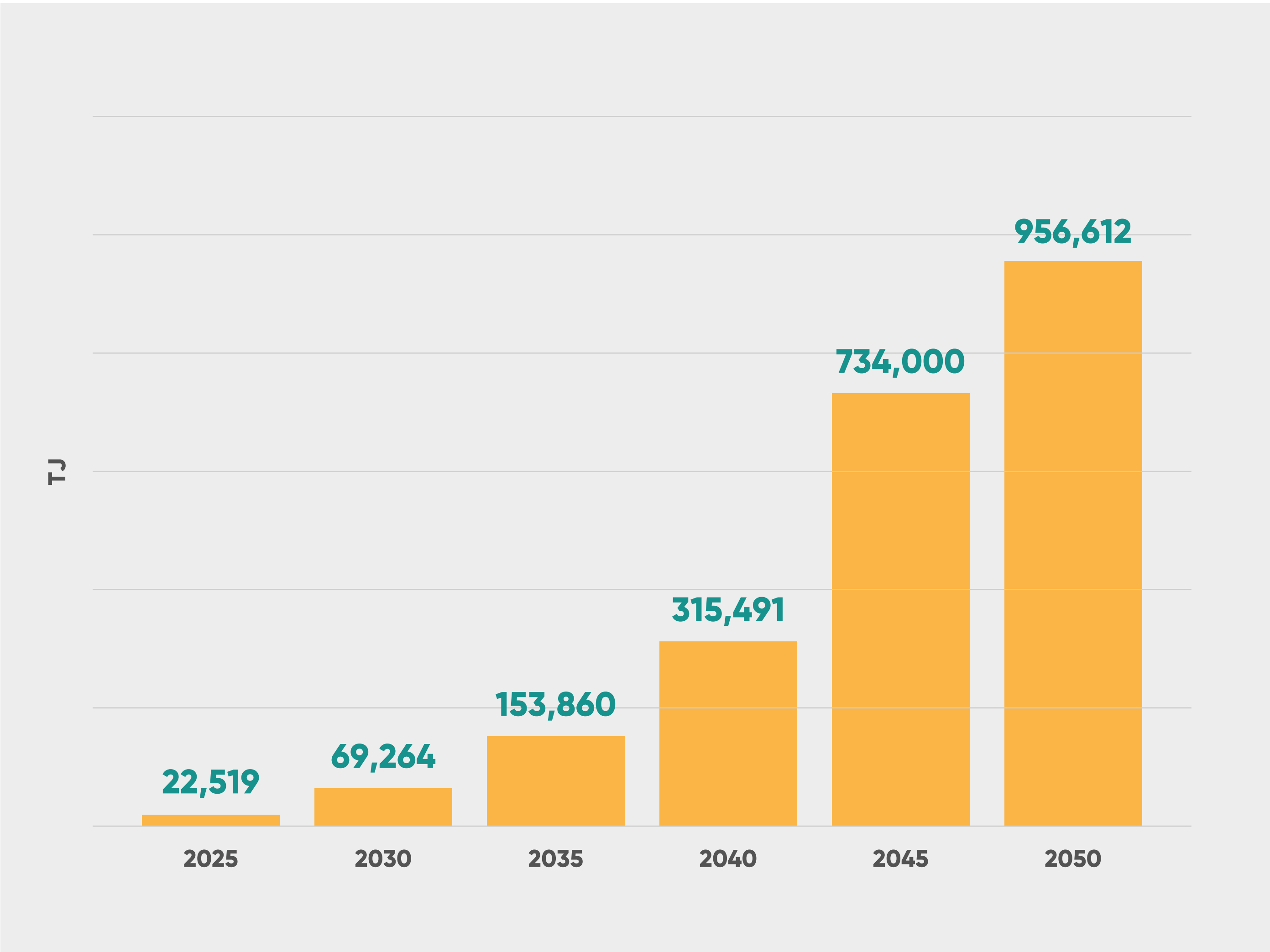
To deal with those issues the Parliament Committee responsible for transport issues (TRAN) has proposed

Figure 8: MARITIME TARGETS ON THE LIMITS ON GHG INTENSITY OF THE ENERGY USED ON-BOARD COMPARED TO 2020.
Source: EC, FUELEU MARITIME REGULATION PROPOSAL.

several changes to the Commission's proposal, including an increase of targets 13% to 20% in 2035 as well as a sub-target requiring ships to use at least 2% RFNBOs by 2030 (although applicable only for large companies operating more than 3 ships). To further reward companies using RFNBOs, a 2x multiplier has been proposed that would double RFNBOs contribution to the overall GHG reduction targets. The level of ambition for 2025 and 2030 remained unchanged however.

In addition to the FuelEU Maritime regulation, the competitive position of low- and zero-emission fuels including clean ammonia will be improved by the implementation of the Energy Taxation Directive proposed as part of the Fit-for-55 legislative package. The regulation imposes mandatory exemptions from taxation for RFNBOs in the maritime sector until 2033 while at the same time introduces minimum taxation levels for fossil-based maritime fuels at 0.9 EUR/GJ. Minimum taxation levels for low carbon fuels in the maritime sector have been proposed at half that level, introduced gradually from 0 EUR/GJ in 2023 to 0.45 EUR/GJ in 2033.

Figure 9: AMOUNT OF MARITIME FUELS (IN TJ) TO BE REPLACED, ASSUMING REPLACEMENT WITH ZERO-EMISSION FUELS ONLY.
Source: HYDROGEN EUROPE.



05 Decarbonisation of ammonia manufacturing

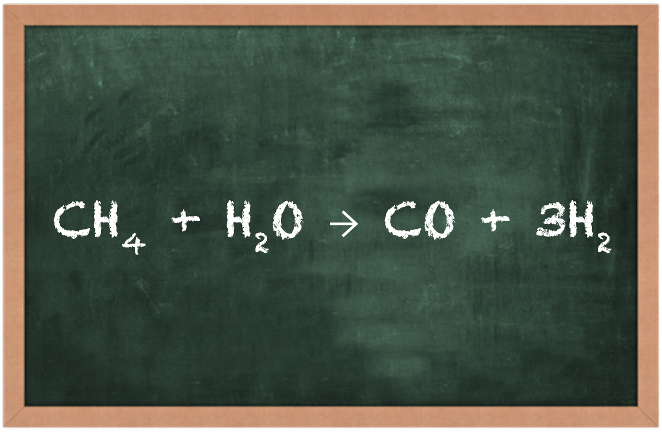
Most of the production of "grey ammonia"[17] in Europe currently involves two main functional steps: the generation of hydrogen via steam methane reforming (SMR) to feed into the Haber-Bosch reactor where ammonia is produced from hydrogen and nitrogen. This chapter presents a CO_2 abatement and cost analysis on different routes for ammonia production, focusing especially on the levelized cost of ammonia (LCOA) for the different options. Most of the emissions are currently concentrated in the hydrogen production step, which is where the uptake of new green technologies can have the biggest impact. This is the step for which different alternatives are presented in the report, while the Haber-Bosch process remains unchanged.

5.1. Benchmark technology – Haber-Bosch synthesis loop with steam methane reforming

5.1.1. Process description and CO_2 emissions

Ammonia is synthesised from nitrogen and hydrogen. The best available source of nitrogen is air, while hydrogen required is currently derived mostly from fossil fuels – whether via steam reforming or partial oxidation (depending on fossil feedstock used).

By far, the most common method to obtain hydrogen for ammonia production – both in the EU as well as worldwide, is via steam reforming of natural gas – i.e. steam methane reforming (SMR). The SMR process is based on the production of syngas (a mixture of CO, H_2 and some CO_2) from the reaction of natural gas and steam. The reaction is endothermic (ΔH = 206 kJ/mol) and natural gas is often used not only as a feedstock but also as a combustion fuel to provide the required heat.



The process begins with the desulphurisation of natural gas that is then fed into the primary reformer to react with steam. Both a catalyst and heat are required for the reaction to take place, the latter obtained through the combustion of fossil fuels. After the primary reforming reaction takes place, the resulting syngas products are fed into the secondary reformer. Here, air is added so that oxygen can

17 / Sometimes also referred to as "brown ammonia".

help combust the gas and provide heat of reaction. While oxygen is depleted from the reaction, nitrogen is kept in the stream for later use in the ammonia synthesis process. In the exothermic water-gas shift reaction, the next step, carbon monoxide can be further converted into hydrogen, reacting with water and producing CO2 as a by-product.

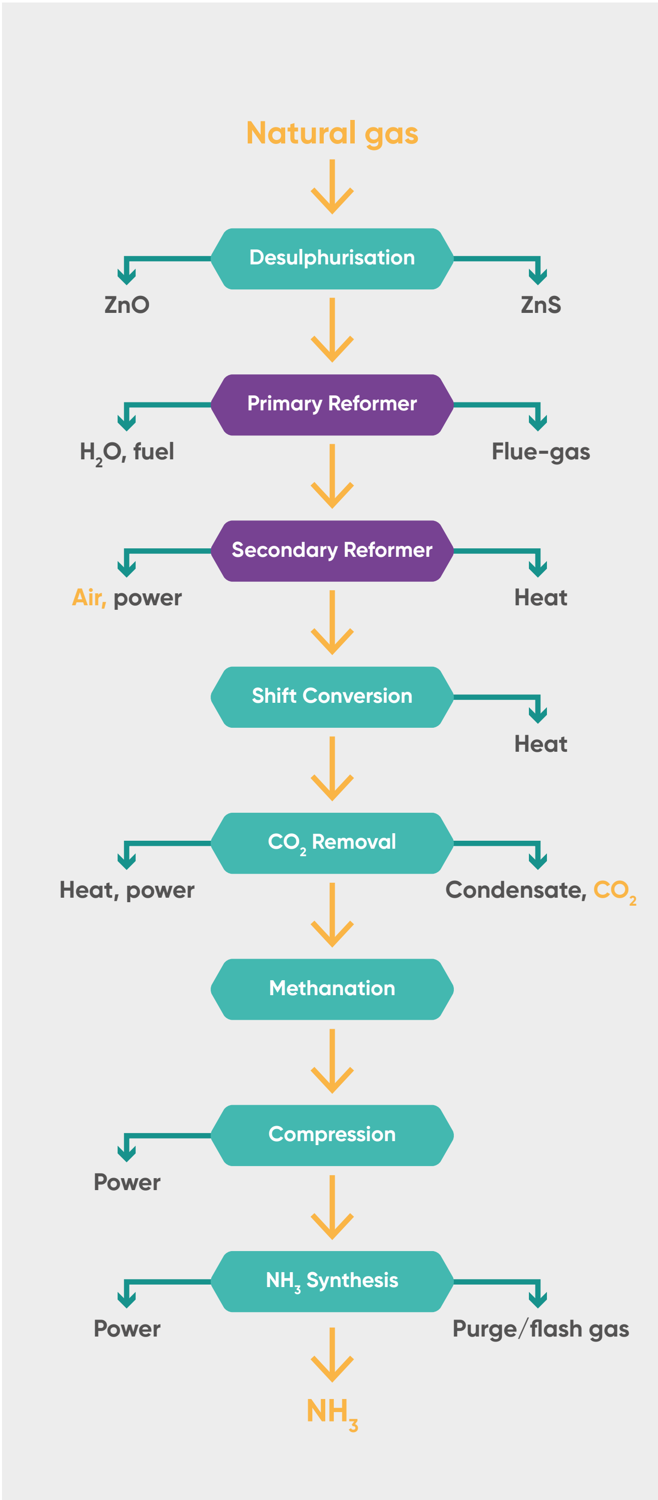
$$CO + H_2O \rightarrow CO_2 + H_2$$

After the water-gas shift reaction takes place, a scrubbing method is applied for CO2 removal. The last step before the preparation for ammonia synthesis is methanation, where any remaining CO is converted back to CH4 to prevent poisoning of the Haber-Bosch catalyst. The remaining syngas stream is then fed into the cooling and compression equipment before serving as an input into the Haber-Bosch process.

The Haber-Bosch chemical reaction was discovered in 1909, serving as the basis for two Nobel prizes awarded to the scientists responsible for both its discovery and optimization into a full-scale operation. The reaction takes both nitrogen and hydrogen as reactants and requires pressure conditions between 150 and 300 bar and temperature between 350ºC and 500ºC for process optimization.

$$3H_2 + N_2 \rightarrow 2NH_3$$

Figure 10: AMMONIA PRODUCTION PROCESS WITH HYDROGEN PRODUCTION THROUGH SMR.
Source: EC, REFERENCE DOCUMENT ON BEST AVAILABLE TECHNIQUES FOR THE MANUFACTURE OF LARGE VOLUME INORGANIC CHEMICALS – AMMONIA, ACIDS AND FERTILISERS, 2007.



One single-pass in the reactor has a conversion rate of around 35%. Recycling is therefore needed, for which nitrogen and hydrogen are once more compressed and fed back into the reactor. The heat recovered from this step of the process can also be used to feed into the SMR endothermic reaction in the form of steam. The integrated process entails an energy consumption of 7.7 MWh/tNH3, including 5.9 MWh/tNH3 of natural gas used as a feedstock only. Including also natural gas used as a fuel for heat and steam generation for the purpose of steam methane reforming, hydrogen production is by far the most energy-intensive step of the ammonia manufacturing process.

Table 2: ENERGY NEEDS TO PRODUCE ONE TONNE OF AMMONIA FOR THE NATURAL GAS SMR ROUTE. **Source:** (DECHEMA & FERTILISERS EUROPE, S.D.) (EIA, 2021).

	Energy intensity (MWh/tNH3)
Feedstock	5.9[18]
Fuel	2.7
Electricity	0.33
Steam	-1.4[19]
Gross	8.9
Net	7.5

The described approach is employed in a vast majority of the existing ammonia plants in the EU. While the average GHG emissions intensity of all ammonia manufacturing installations included in the EU ETS in 2016/2017 was 1.972 tCO2/tNH3, using the Best Available Techniques approach it is possible to reach carbon intensity of ammonia production via the SMR route of around 1.8 tCO2/tNH3 of direct emissions (IEA, 2021). Considering that the SMR process alone emits, on average, around 9 tCO2/tH2 and that 0.18 tonnes of hydrogen are required to produce one ton of ammonia, hydrogen generation is responsible for most of the direct emissions of the overall process. **It is therefore clear that in order to decarbonise ammonia manufacturing, use of low-carbon hydrogen is key.**

It should be also noted that the emissions outlined above include only direct emissions resulting from the combustion of natural gas. The life cycle carbon footprint of natural gas is however higher. Including GHG emissions from natural gas production, processing, transportation and storage of 9.7 gCO2eq/MJ[20] and average EU carbon intensity of electricity generation of 265 gCO2eq/kWh (European Environment Agency, 2022), **total emissions of ammonia manufacturing from natural gas via SMR would be around 2.3 tCO2/tNH3.**

5.1.2. Levelized cost of ammonia from SMR

As natural gas consumption for steam methane reforming is the most energy intensive step in the ammonia manufacturing process it is no surprise that ammonia production costs are strongly correlated to natural gas prices. With the current (Nov 2022) natural gas prices of around 110 EUR/MWh, total costs of grey ammonia production can be estimated at around 1,125 EUR/t – with natural gas costs responsible for almost 75% of the cost. Another important cost element is the cost of CO2 emissions, adding around 12% of the cost (assuming no free allowances).

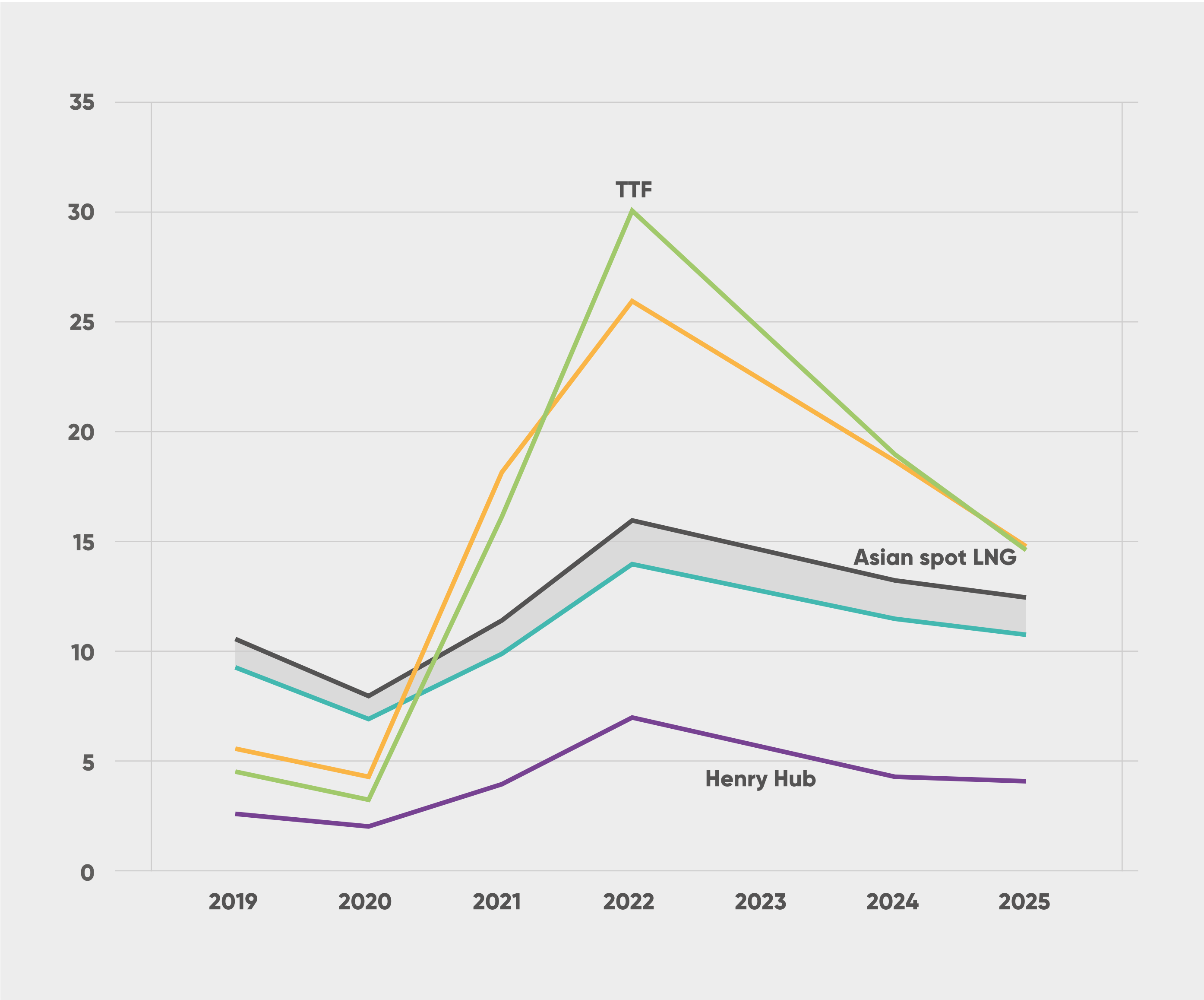
Such high production costs are however not a fair reflection of long-term competitiveness of grey ammonia. Firstly, ammonia manufacturers in the EU can benefit from free allowances. Considering 1.8 tCO2/tNH3 emitted through the SMR process, a 500,000 ton/year plant would require around 860,000 allowances (EUA), which considering a 75 EUR/EUA price would translate into additional costs of almost 65 million EUR per year (European Commission, 2021). However, as the EU ETS benchmark for ammonia

18 / Dechema, Fertilisers Europe, Technology options for CO2-emission reduction of hydrogen feedstock in ammonia production.
19 / EIA, Ammonia Technology Roadmap.
20 / Standard value for natural gas upstream emissions proposed by the European Commission in the Delegated Act to the Renewable Energy Directive on establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels.

manufacturing for the period of 2021-2025 has been set at 1.57 tCO_2/tNH_3, free allowances can reduce the CO_2 emission costs by up to 80%.

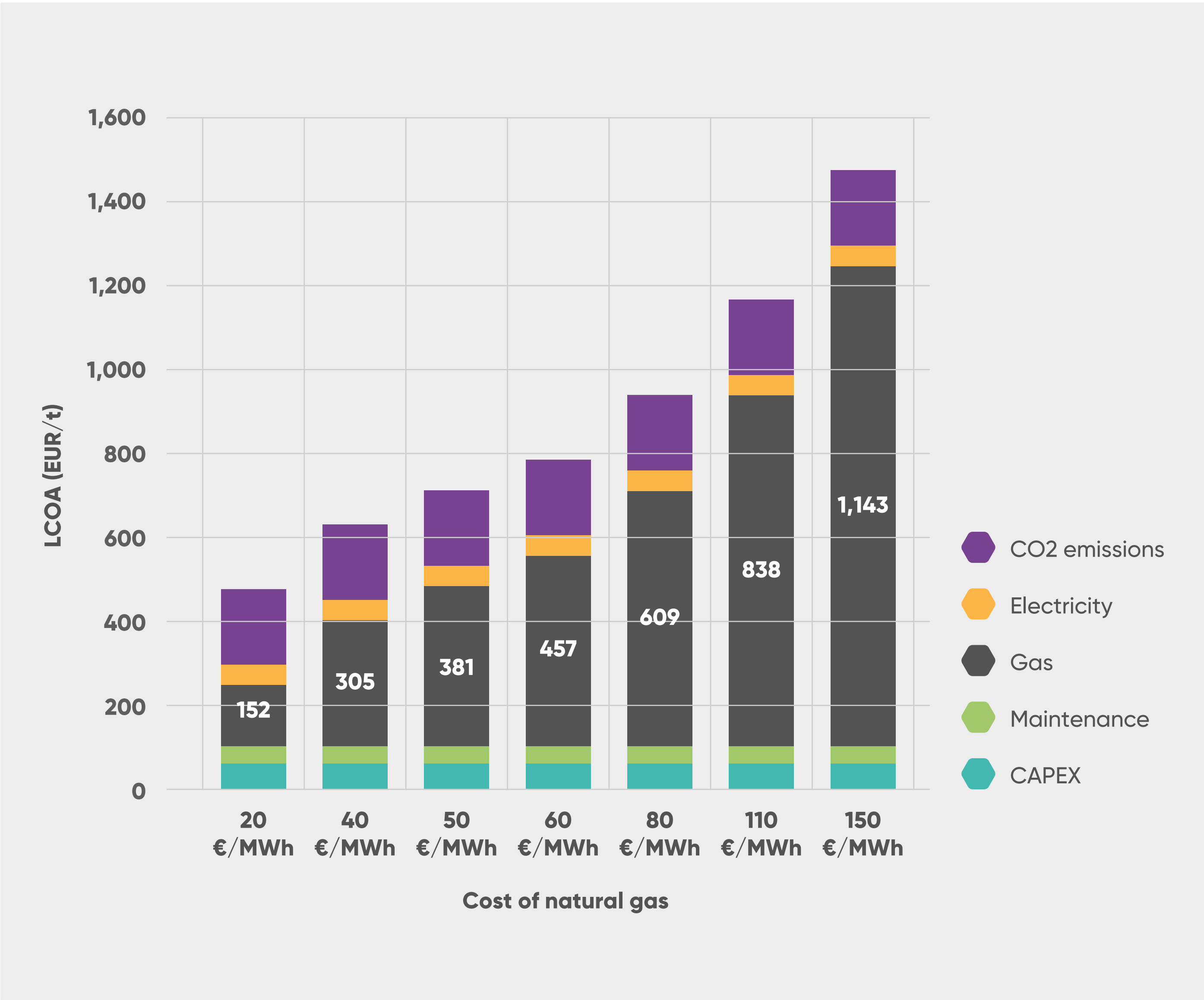
More importantly, the production costs are inflated by the current high natural gas prices. At historical natural gas price levels of around 20 EUR/MWh, the levelized costs of grey ammonia production were around 440 EUR/t with marginal costs below 300 EUR/t. While a return to such low natural gas prices might not be possible even in the medium term, the IEA still expects a gradual fall in the coming years – up to around 50 EUR/MWh in 2025.

Figure 11: NATURAL GAS PRICE ASSUMPTIONS, 2019-2025. UPDATE OCT 2022. PRICES IN USD/MBTU.
Source: IEA.



Were natural gas prices to fall back to 50 EUR/MWh, the LCOA for grey ammonia would be at around 667 EUR/t with marginal costs at around 565 EUR/t. This is most likely a better reflection of the cost levels which ammonia based on clean hydrogen needs to reach, in order to be able to compete with its fossil fuel based equivalent. Furthermore, as most ammonia plants in the EU have been built in the 1960s and 1970s, the plants are in most cases long amortised by now, which means that a decision to invest in a low-carbon alternative might be made based on a comparison with marginal costs only. The estimated LCOA for grey ammonia is presented on the graph below.

Figure 12: COSTS OF PRODUCTION OF GREY AMMONIA IN EUROPE DEPENDING ON NATURAL GAS PRICES.
Source: HYDROGEN EUROPE.



5.2. Carbon Capture and Storage as an option to decarbonise ammonia production

5.2.1. Technical considerations

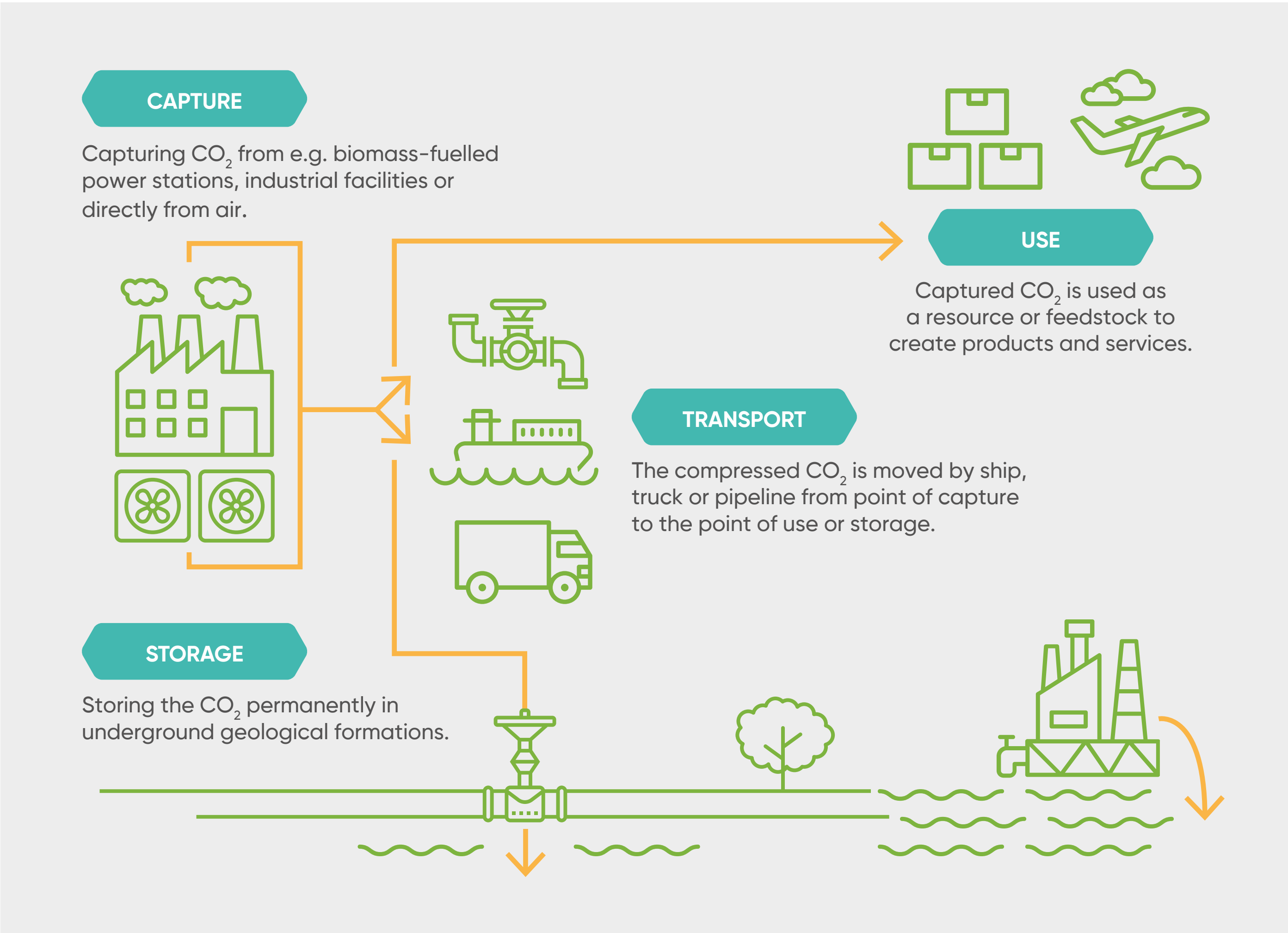
Carbon capture for usage and storage (CCUS) technology allows for the reduction of emissions from hard-to-abate sectors – including ammonia manufacturing. The captured CO2 can either be used as a feedstock for other chemical processes or get liquified, distributed, and stored underground in salt caverns, for example. Hydrogen produced making use of CCUS technology is often called blue hydrogen, which gives origin to blue ammonia.

There are plenty of benefits of the technology. One of the main benefits is that, by adding equipment to capture the CO2 before it is emitted to the atmosphere, industrial facilities are able to carry out their processes as usual.

The other key benefit is a relatively low cost of CO2 capturing, especially from gas streams like the gas mixture output from SMR, where the concentration of CO2 is significantly higher than in the flue gas resulting from the combustion of fossil fuels. This is one of the reasons that the ammonia industry is the biggest supplier of CO2 to the food and beverage industry.

Around the world, there are currently 26 CCS plants in operation, of which three are associated with hydrogen production, two of them for fertilizer production (Pembina, 2021).

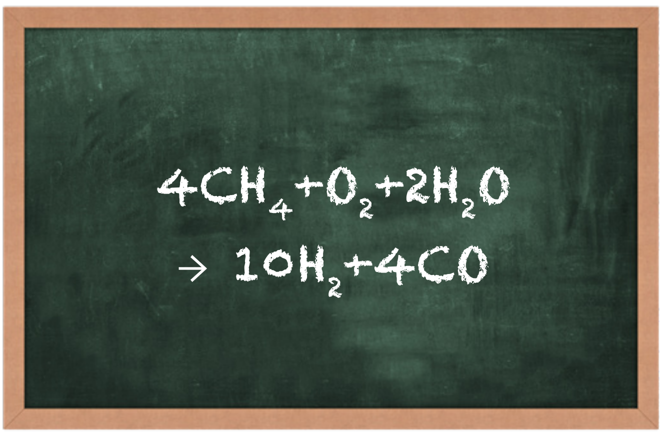
Figure 13: CARBON CAPTURE AND USAGE OR STORAGE.
Source: EUROPEAN COMMISSION.



Using the CCS technology to decarbonise exiting ammonia plants has, however, its limitations as well. Up to around 40% of the total emissions from the ammonia production are concentrated in the flue gas. As a result, even if the SMR facility with CCUS would achieve a CO2 capture rate of 95%, since only about 60% of carbon is emitted via the process stream, the overall CO2 reduction would be only 57% of direct emissions and 45% of total emissions.

According to (Collodi, et al., 2017), if emissions from the flue gas are also captured, an overall 90% rate of capture can be achieved on CCUS, but the cost of CO2 avoidance raises from 47.1 EUR/tCO2 to 69.8 EUR/tCO2, considering the technology's CAPEX and OPEX for both capture and compression of CO2 (Collodi et al, 2016). Such high rates of capture can be, however, hard to achieve in ammonia plants where the CCS technology is retrofitted in existing installations. Ignoring this fact and assuming a 69.8 EUR/tCO2 cost for CO2 avoidance, a 500,000 t/y ammonia plant would see around 58 million EUR additional costs every year, or 117 EUR/tNH3.

Alternative hydrogen production processes from natural gas include autothermal reforming (ATR). ATR reacts hydrocarbons (typically natural gas) with steam and pure oxygen to produce a syngas consisting of CO, H2 and CO2.

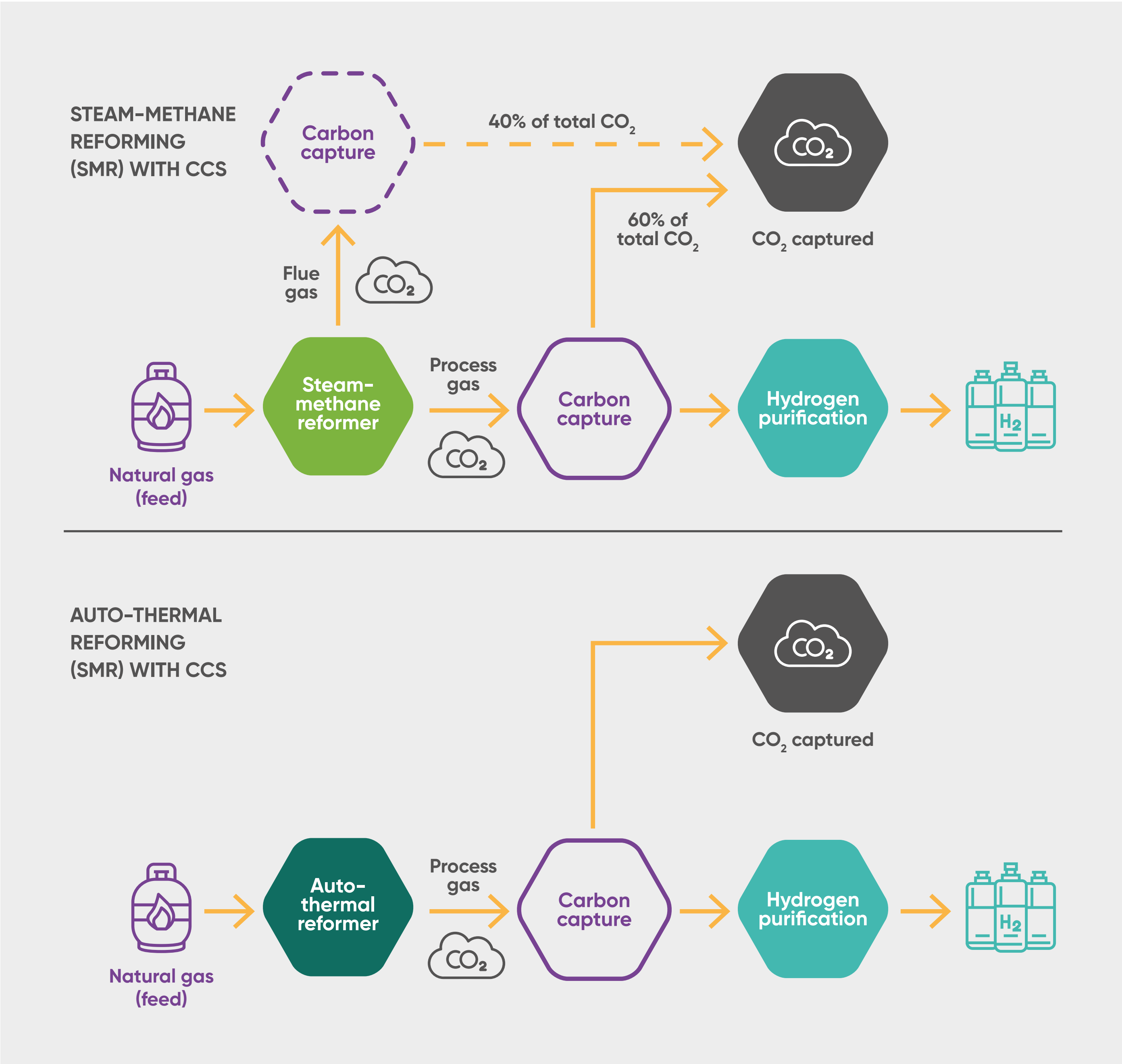


As it involves internal combustion of part of the methane feedstock, which provides the heat required for the SMR reaction, only minimal external energy inputs are required in ATR, just for preheating the inputs. Some drawbacks of the technology include the fact that ATR does not produce excess steam for possible export (e.g. to power an adjacent urea plant). Furthermore, ATR requires an air separation unit to isolate oxygen and nitrogen, whereas SMR can use air directly, and consequently requires significantly more electricity than an SMR hydrogen generation unit. Nevertheless, because a higher proportion of the CO2 produced is concentrated (a lower proportion is dilute flue gas CO2) ATR is more amenable to the application of CCUS.

ATR may therefore become the preferred technology for new-build natural gas facilities where the aim is to achieve near-zero emissions of ammonia production (IEA, 2021).

Overall, the ATR technology allows for decarbonization rates above 95%.

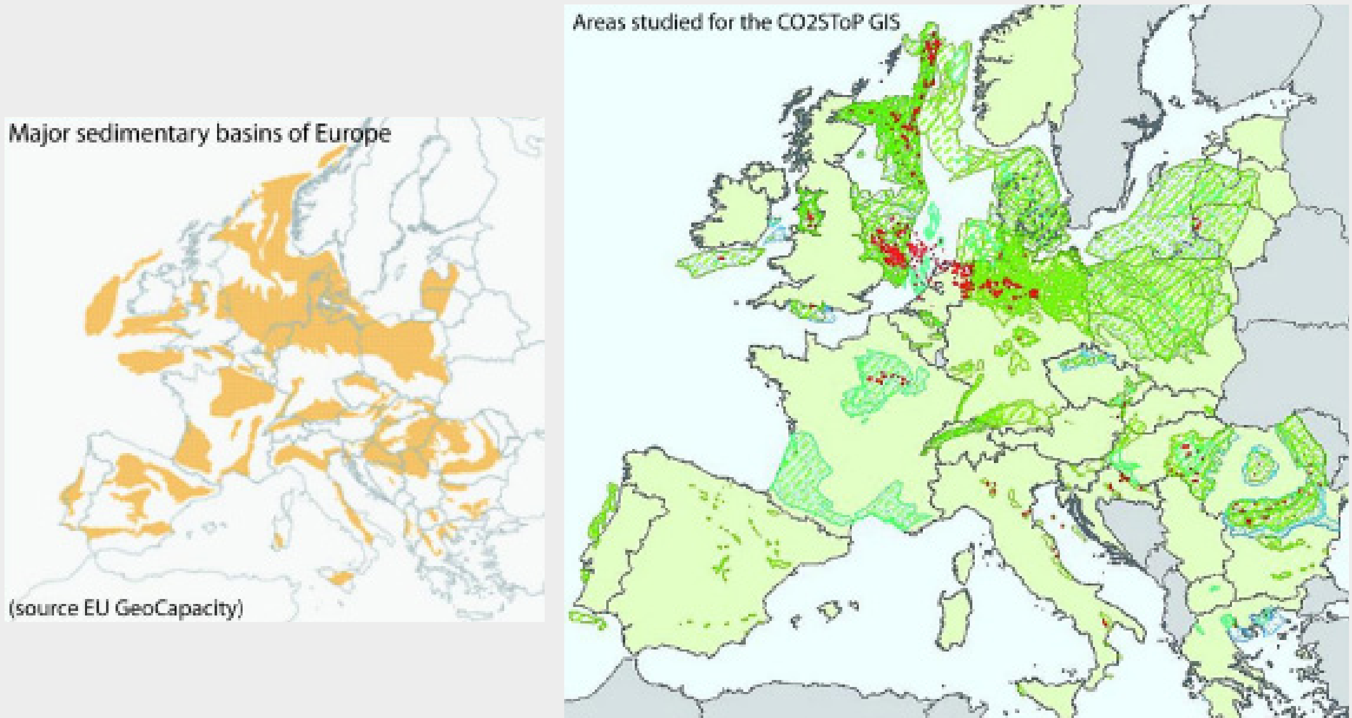
Figure 14: CARBON CAPTURE OPPORTUNITIES FOR SMR AND ATR PROCESSES. SOURCE: PEMBINA INSTITUTE.



After its collection, CO2 must be stored in specific underground geological formations. While most of the favourable locations have not been exploited yet with concrete project plans, there is considerable potential in Europe to do so (as seen in Figure 15). However, CO2 storage will not be immediately available in all industrial locations of Europe and proper transportation infrastructure is therefore needed.

The transport of CO2 can be done either through designated pipelines, railways, trucks or by ship. To ship the CO2, a prior process of liquefaction is necessary. Pipelines are normally the most cost-effective way of gas transport. However, there are only a few CO2 pipelines deployed in Europe. They are also not able to carry the CO2 overseas, for which shipping is the best option, although as mentioned prior liquefaction is necessary.

Figure 15: MAJOR SEDIMENTARY BASINS IN EUROPE AND REPORTED RESERVOIRS. SOURCE: CO2STOP PROJECT.



Left hand-side figure:

- Sedimentary basin

Right hand-side figure:

- Countries studied
- Countries not participating in CO2 stop project
- Aquifer daughter units
- Hydrocarbon daughter units
- Storage units
- Formations

Alternatively to storage, CO2 can also be used as a feedstock for different chemical processes, namely in the food industry for the production of beer and soda, fertilizer production in the urea synthesis process, or the production of synthetic fuels such as e-kerosene. It must be noted, however, that in most cases (urea and e-kerosene, for instance) the CO2 still gets released to the atmosphere during field application of the products.

5.2.2. Carbon footprint of blue ammonia

Even though CCS technologies offer significant decarbonisation opportunities, the production of low-carbon ammonia would still generate non-trivial amounts of emission. Considering the two extreme options, SMR with carbon capture only from process gases and a comprehensive ATR with CCS the total carbon intensity of blue ammonia would vary between 1.3 and 0.6 tCO2/tNH3 respectively, while the emissions attributable to the hydrogen feedstock would be 6.4 and 2.2 tCO2/tH2 respectively.

For reference, according to the EU taxonomy for sustainable finance, in order for anhydrous ammonia manufacturing to be considered as sustainable (i.e. contributing substantially to climate change mitigation) it would have to be produced from hydrogen with an LCA carbon footprint of no more than 3.0 tCO2e/tH2[21].

This means that ammonia produced via SMR with CCS, would not meet the threshold established for ammonia manufacturing in the EU taxonomy for sustainable finance – unless carbon capture was applied also to heat generation. Alternatively, natural gas feedstock would have to be replaced by a low-carbon alternative, e.g. biomethane or low-carbon hydrogen itself.

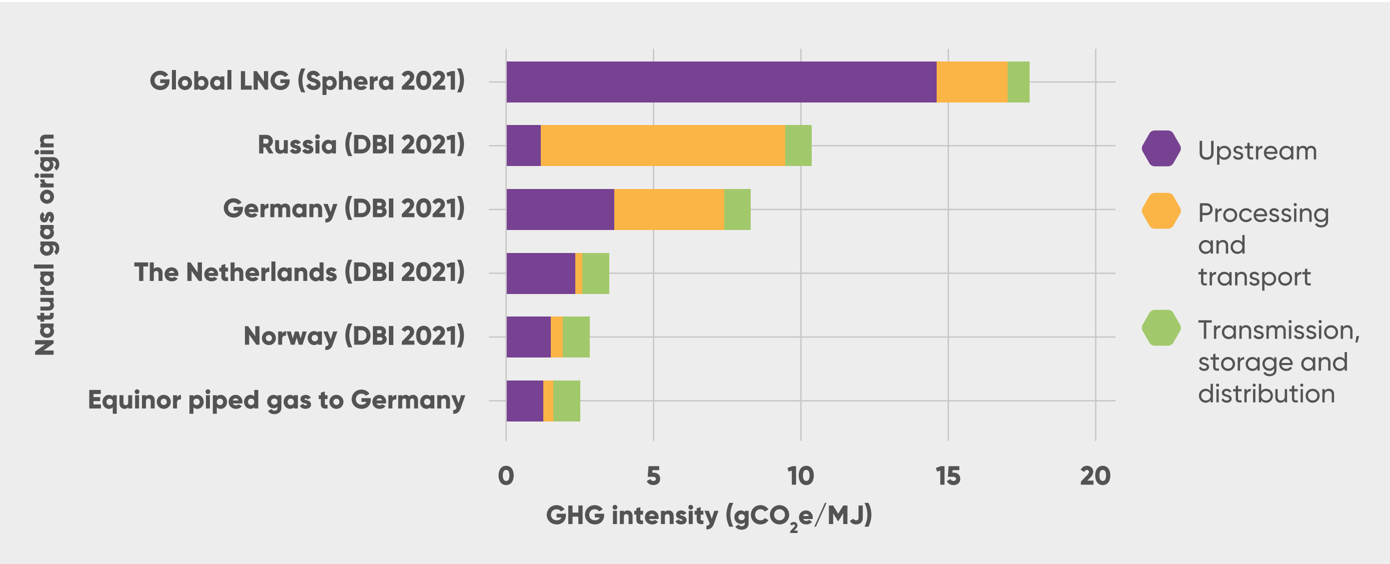
On the other hand, hydrogen, and by extension ammonia, produced via ATR with CCS, would be well below the EU taxonomy threshold.

Furthermore, it should be noted that for the ATR + CCS route, the calculated GHG emissions consist mostly of indirect emissions originating from natural gas supply and electricity generation. Both of these can vary significantly depending on the energy source. The benchmark value for upstream emissions for natural gas of 9.7 gCO2eq/MJ, proposed by the European Commission, is based largely on emissions for natural gas delivered by pipelines from Russia. However, a longstanding ban on routine flaring, carbon taxation as well as the common use of fully welded pipelines and relatively shorter distances to main markets, combined with the use of low carbon hydropower electricity at onshore facilities result in a significantly lower carbon intensity of natural gas supplied from the Netherlands and Norway. On the other hand, the use of LNG imported from outside of the EU as feedstock would be characterised by a higher emission intensity.

The differences in the carbon intensity of natural gas supply to Germany, depending on the origin of the gas, are presented in the graph below.

With the following gas supply GHG intensities the carbon

Figure 16: COMPARISON OF GHG INTENSITY OF EQUINOR'S NORWEGIAN PIPED GAS TO GERMANY IN 2020 AND THE GERMAN PIPED GAS SUPPLY. DOWNSTREAM DATA FOR EQUINOR'S PIPED GAS TO GERMANY IS DERIVED FROM DBI 2021.
Source: (EQUINOR, 2021).



21 / Alternatively, the criteria for substantial contribution to climate change mitigation would also be met if ammonia would be produced from waste water.

footprint of hydrogen from Norway or the Netherlands would fall to around 1.0 tCO2e/tH2. At the same time however, blue hydrogen produced from LNG imported from outside of the EU would have a carbon intensity of 3.4 tCO2e/tH2 – i.e. above the EU taxonomy threshold. By extension, ammonia produced from such hydrogen would also not be recognised as contributing towards climate change mitigation.

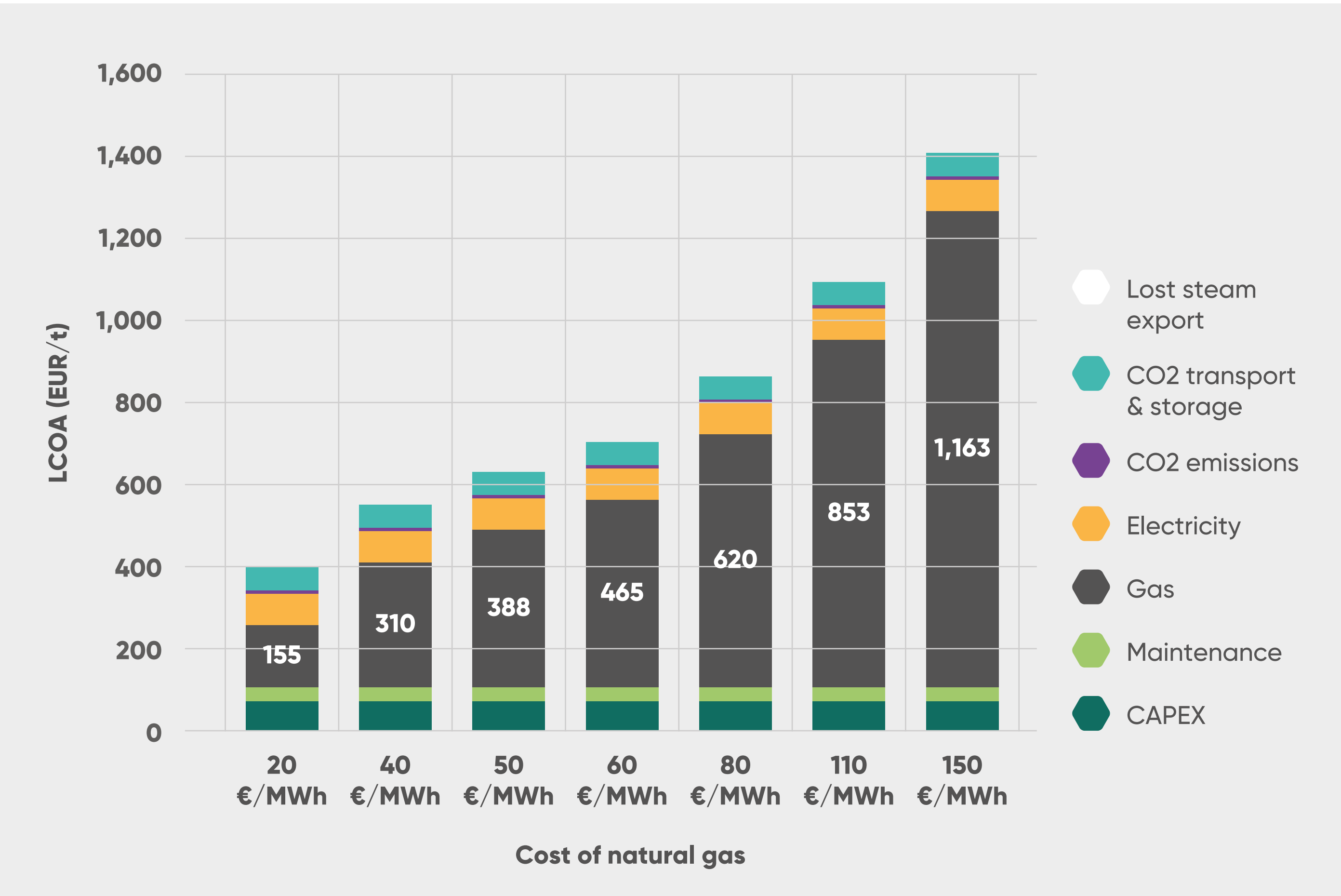
5.2.3. Levelized costs of blue ammonia

Because ATR plants do not produce excess steam for export which could be used further downstream (e.g. for urea production), and require more electricity, mainly to supply the air separation unit that sources nitrogen from the air, it is overall slightly less energy efficient, on a net basis, than SMR (IEA, 2021). This is why ATR technology is rarely employed in existing ammonia plants, where SMR is the dominant approach. The cost difference is however small enough to suggest that it might become the preferred technology for new blue ammonia plants – especially if ambitious CO2 reduction goals are set.

We estimate that even taking into account increased electricity consumption, lost steam export as well as adding costs of captured CO2 transportation and permanent storage of 30 EUR/tCO2, at current natural gas prices, **the CO2 break-even price, using the ART+CCS approach is around 51 EUR/tCO2.**

Given current ETS EUA price level of 75 EUR/tCO2, blue ammonia produced with the ATR+CCS approach would be cost competitive with the SMR approach. This doesn't however include the potential revenues from sales of CO2 to, for example, the food and beverage industry, which would reduce the profitability of permanent storage of CO2.

Figure 17: LEVELIZED COSTS OF BLUE AMMONIA (LCOA) – ATR+CCS.
Source: HYDROGEN EUROPE.



5.2.4. Selected blue ammonia projects

The use of CCS technology in the European ammonia sector is already planned in several locations.

One example is the Barents Blue project, developed by Horisont Energi, in partnership with Var Energi and Equinor, aiming at the production of blue ammonia by 2025.

The goal of the project is for the Markoppneset plant in Northern Norway to achieve close to zero emissions, focusing not only on carbon capture but being also self-sufficient on power with limited reliance on the Norwegian power grid.

The plant will produce 600 tonnes of hydrogen per day making use of natural gas as a feedstock in an auto-thermal reforming process, which in turn can give origin to around 3,000 of ammonia produced per day, or over 1 million tonnes per year. The CO2 capture technology is aiming at achieving a capture rate of 99%, with 2 million tonnes of CO2 emissions avoidance. The captured CO2 will be stored at the Polaris reservoir, Horisont Energi's storage system located at the seabed, off the coast of Finnmark in Norway. The reservoir contains an estimated available storage capacity of 74 million tonnes of CO2.

While the final investment decision is expected at the end of 2022, the project has already achieved important milestones, including most of the technical studies for the concept phase and the political approval from the municipality to use the site.[22]

Also in 2025, one of the biggest ammonia producers in the world, Yara, is planning for a cross-border CO2 transport and storage project where around 800 kt of CO2 emissions from the Yara Sluiskil plant in the Netherlands will be transported and stored in Norway. The project will be implemented in collaboration with Northern Lights, responsible for the transportation and storage of CO2 to the seabed off the coast of Oygarden.[23]

Another important European project aiming to utilize the CCS technology is Kairos@C[24]. The project is led by Air Liquide and BASF, intending to implement the CCS technology in the BASF chemical site in Antwerp, Belgium. CO2 will be captured from 5 different production facilities, including two hydrogen plants, two ethylene oxide plants and one ammonia plant. The captured CO2 will then be liquified and transferred to the port of Antwerp, from where it will be shipped to the North Sea and permanently stored underground. It will use the CO2 transport and export infrastructures being built by the consortium, which will make the Port of Antwerp a carbon-capture hub, pioneer in Europe. These infrastructures created will be available for other CCS projects nearby. Besides Air Liquide and BASF the consortium includes also Borealis, ExxonMobil, INEOS, TotalEnergies and Fluxys.

The Cryocap™ technology, which will be used in the Project, can also be applied in other energy-intensive sectors for CO2 streams with a CO2 concentration in the range between 15% and 95%, such as in oxy-combustion in the power sector or in cement manufacturing, with strong replication potential throughout the industry.

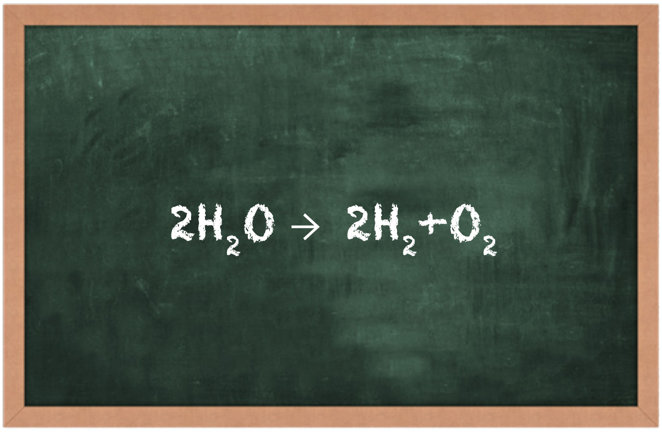
The project has already started construction works and is planned to become operational in 2025, where it could potentially avoid over 1.5 Mt of CO2 emissions. It has won a 357 million EUR grant from the ETS Innovation Fund in 2022 and got a significant financial support from the Flemish government.

5.3. Electricity-based ammonia production

5.3.1. Process description

As an alternative to the previously described steam or autothermal reforming of natural gas processes, hydrogen can also be produced via water electrolysis. In this method, electricity is used to break the water molecule into molecular hydrogen and oxygen.

22 / More information at https://horisontenergi.no/wp-content/uploads/2023/02/Barents-Blue-Project-Flyer-2021.pdf
23 / More information at https://www.yara.com/news-and-media/news/archive/news-2022/major-milestone-for-decarbonising-europe/
24 / More information at https://kairosatc.eu/



For industrial large-scale applications, currently, there are two dominant electrolysis methods, thus two types of electrolysers that are most likely to be used at multi-megawatt- and gigawatt-scale. The first is polymeric proton exchange membrane (PEM) electrolysis and the second is alkaline electrolysis (AE), the latter has been in use for over a century.

Alkaline water electrolysis' operation is mainly stationary at low operating temperatures (40-90 °C) and pressures (1-30 bar). Polymer electrolyte membrane electrolysis is also operated at low temperatures (20-100 °C), but at higher pressure levels (30-50 bar).

Alkaline electrolysers use a liquid electrolyte (in most cases, potassium hydroxide - KOH solution) with a porous separator between the anode and cathode. In this case, hydroxide ions pass through the separator via the liquid solution to form oxygen and water. At the second electrode, hydrogen is co-generated with the hydroxide ions. The electrolysis process can be started and brought to maximum production in less than 30 minutes. The capacity can be changed between 15% and 100% in about 10 minutes for an alkaline atmospheric electrolyser. For high-pressure electrolysers, capacity changes from 10% to 100% take only seconds or less.

PEM technology uses a solid polymer electrolyte membrane and direct current to separate hydrogen (via protons) and oxygen from water. The electrolyte in a PEM-type electrolyser allows for selective transport of H+ protons from the anode through the membrane to the cathode, preventing hydrogen and oxygen from mixing.

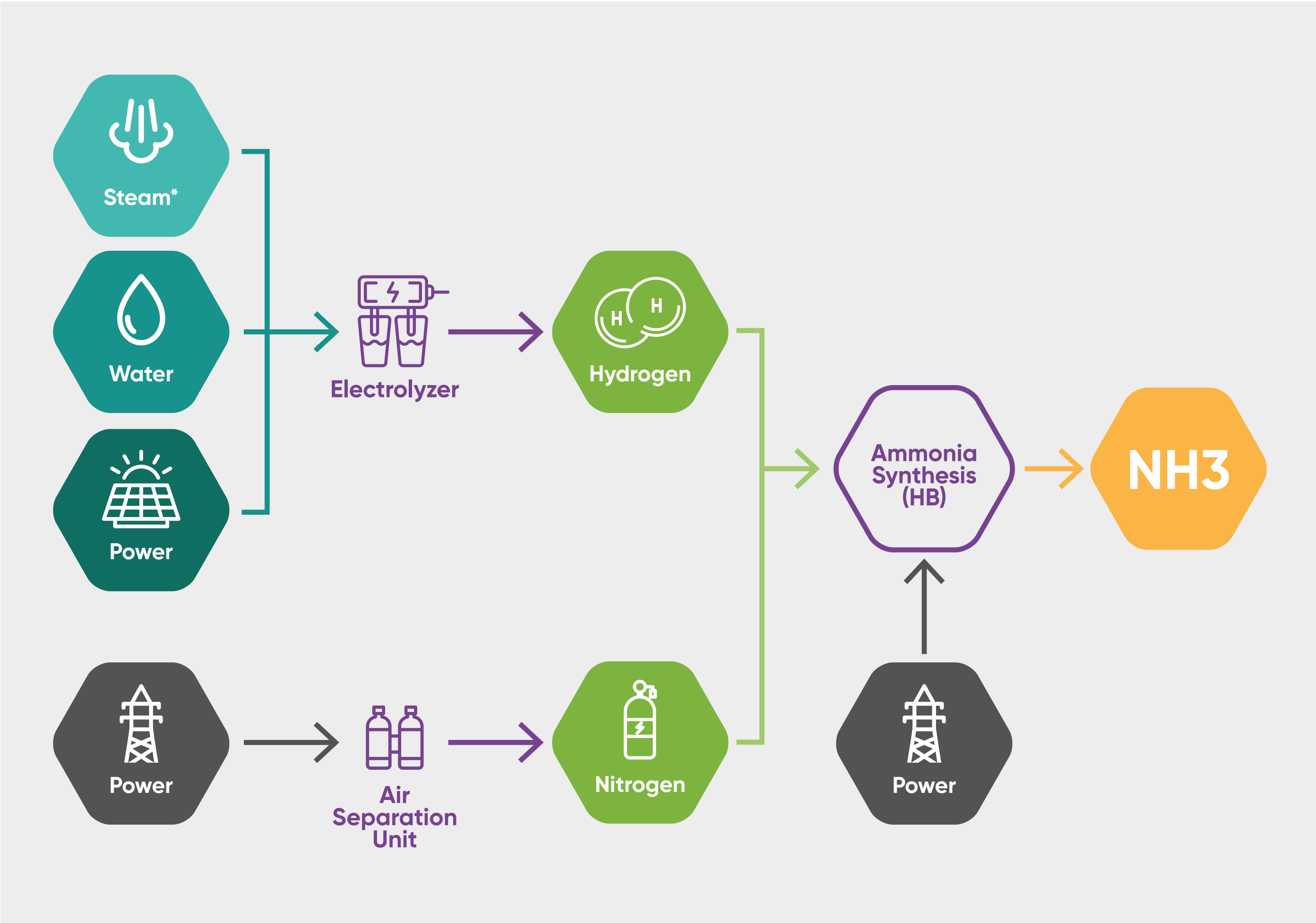
The main advantage of the PEM technology is that it has the capacity for a dynamic range of operation from 0 to 100% making it ideal for hydrogen production using excess renewable energy with time-varying available power. Another advantage is the possibility of obtaining ultra-pure hydrogen (purity class >=5.0 or >=99.999%). It is also compact, reliable and maintenance-free, suitable for small and medium-sized industrial applications, although it is now also in operation for large-scale applications due to its modularity.

The decomposition reaction of water to hydrogen is highly endothermic. To drive the reaction by electrical energy, a minimum energy input of 39.4 kWh/kg of hydrogen is required, but additional losses in the electrolysis stack, electrical transformation and rectification or hydrogen drying, increase the required energy input to 53-57 kWh/kg (4.7-5.1 kWh/Nm3) for state-of-the-art electrolyser systems. With large scale systems, some BOP energy savings can be achieved, reducing the overall energy consumption. For multi-MW electrolysis plants using alkaline technology to as low as 50 kWh per kg hydrogen.

Although lower in the TRL development scale and not well suited to working with variable load, if a stable electricity supply can be ensured, together with a source of waste heat, Solid-oxide electrolysers could also be an option – potentially offering significantly higher energy efficiency.

Apart from the electrolyser, switching to an electrolytic hydrogen supply would require also other additional equipment. As was the case with ATR, a new supply of nitrogen needs to be ensured with an Air Separation Unit (ASU) – usually via a cryogenic distillation process if a constant load can be ensured or via Pressure Swing Adsorption for a setup based on variable renewable power. The latter would consume more electricity but is more suited for variable load operation. Compared to the common ammonia manufacturing based on SMR, switching to electrolysis would also eliminate excess steam generation which can be used for other processes further downstream.

Figure 18: NH3 FROM H2 PRODUCED BY ELECTROLYSIS.
Source: HYDROGEN EUROPE.



Note: Steam is only required as an input in case of a high-temperature electrolyser.

One key impact of the switch to hydrogen production based on water electrolysis and a departure from natural gas reforming would however occur further downstream.

The CO2 from natural gas reforming is routinely captured during the process of producing ammonia and used on site for urea synthesis. Such installations have been operating commercially in this way for decades because of the inherent need to separate the CO2 from the hydrogen required for ammonia production, and the relatively high share of ammonia that is converted to urea. **Of the roughly 250 Mt CO2 generated directly from the use of fossil fuel feedstocks (direct process CO2 emissions), around 130 Mt CO2 (52%) are used directly to produce urea** (IEA, 2021).

To produce one tonne of urea, around 0.73 tonnes of CO2 and 0.58 tonnes of ammonia are required. It should be noted, however, that the consumption of CO2 in the urea production method does not mean carbon sequestration. Once used as a fertilizer, the decomposition of urea will release CO2 again into the atmosphere.

As production of hydrogen via water electrolysis does not generate any direct CO2 emissions, switching to this technology as the main source for hydrogen will therefore eliminate the supply of CO2 needed for urea synthesis. In this case, in order to maintain the same product portfolio of the integrated fertilizer plant, the CO2 would have to be sourced from somewhere else, for example – from other CO2 emitting industries like cement or other hard-to-abate sectors, where the capture of CO2 is one of the main options to reduce emissions, or direct air capture. Alternatively, if no viable CO2 source is available, the replacement of urea production by ammonium nitrate and calcium ammonium nitrate is also an option.

Either way, this will be an important consideration in the decision of whether to choose electrolysis or CCS as the preferred decarbonisation option for an integrated ammonia plant.

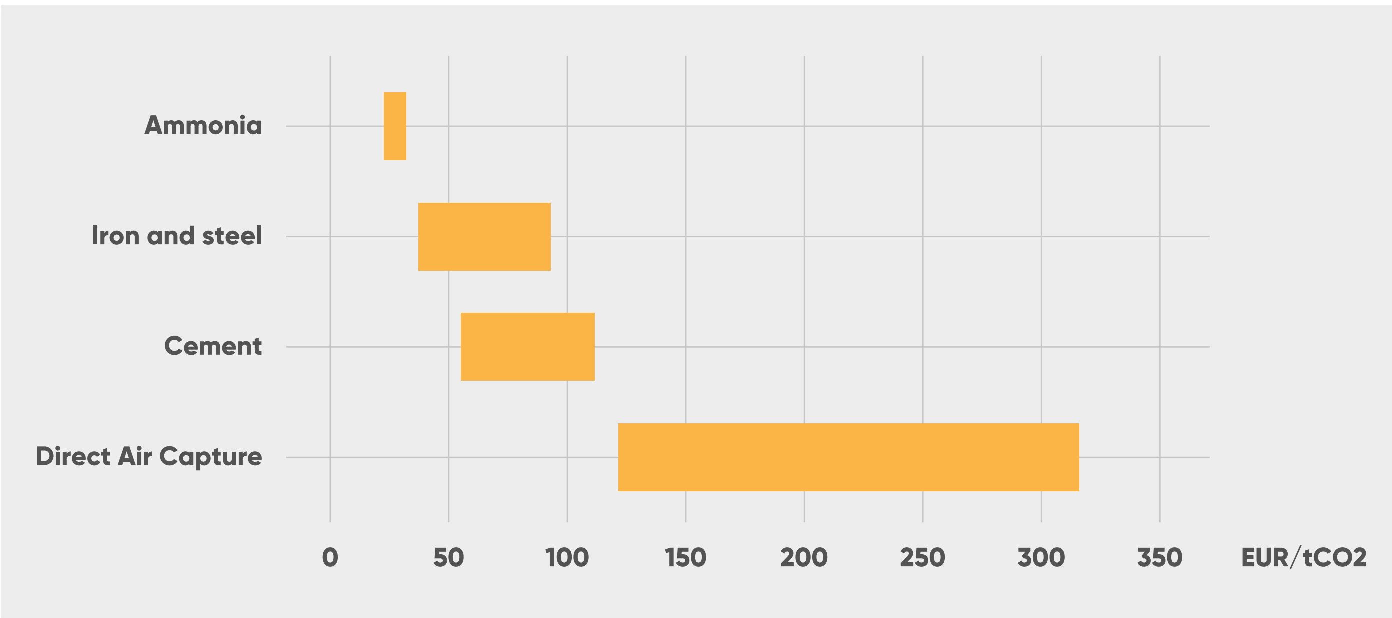
As mentioned previously, the cost of capturing CO2 greatly depends on the CO2 concentration level in the gas stream it is captured from. As CO2 concentration in SMR process gas is higher, compared to flue gases from fossil fuel combustion or air in general, a departure from natural gas reforming will inevitably lead to higher CO2 supply costs and an increase in urea production costs. CO2 captured from the cement industry, for example, could cost between 56 and 112 EUR/t – so significantly more than CO2 captured from SMR, which can be estimated at between 25 to 30 EUR/t[25]. Another alternative for the supply of CO2 for urea production is Direct Air Capture. Despite currently being the most expensive source of CO2, with costs ranging between 120 to 315 EUR/t, it would be the most sustainable option, as it would result in carbon neutral urea.

In addition to higher capture costs, supplying CO2 from external sources would also entail additional costs related to storage and distribution of around 10 USD/t (9.3 EUR/t), although those can vary significantly depending on the transportation distance.

With a CO2 and ammonia consumption of 0.73 tCO2/tUrea and 0.58 tNH3/tUrea, if CO2 was to be supplied from a nearby cement plant, the cost of CO2 could be around 48-88 EUR/tUrea, including both the capturing and distribution costs. For reference, the current market price for grey urea, is 210 EUR/t. If on-site Direct Air Capture is used, the CO2 cost would add 88-230 EUR per tonne of urea – i.e. 42-110% of its current market price. These are significant additional costs for the plant, which could well make urea production not profitable, and as urea is currently the most used fertilizer in the world, the availability of cheap CO2 source will be a key factor determining a switch to fully electrified ammonia production. Assuming that, on average, around 52% of CO2 from ammonia production is used for urea synthesis, low carbon electrolytic ammonia production costs would have to be lower than grey ammonia by around 47 EUR/tNH3 to make up for the extra costs of CO2.

25 / IEA https://www.iea.org/commentaries/is-carbon-capture-too-expensive

Figure 19: LEVELIZED COST OF CO2 CAPTURE FROM VARIOUS EMISSION SOURCES.
Source: IEA.



It should also be noted that, besides urea manufacturing, due to its relatively low cost, the carbon dioxide originated in the ammonia industry is also widely used in the food and beverages industry, e.g. to dry fruit and vegetables in order to extend their shelf-life and for the refrigeration of food in transit. If CO_2 from the ammonia industry would no longer be available, the food industry would need to secure other source of supply, which would lead to an increase in food prices. Losing this revenue stream would further reduce the profitability of switching to a fully electrified ammonia production route.

Considering the above, in a transition phase, an operator might be tempted to opt for a hybrid plant concept, in which natural gas is still used as a second feedstock and a reformer section is included. This would allow for a flexible operation of the electrolyser and maintain the high level of process and heat integration of today's ammonia plants. Investment in an air separation unit could be avoided as well. In addition, CO_2 generated in the reformer can directly be used in subsequent urea production or exported for use in the food industry (DECHEMA, 2017).

Application of such a hybrid approach would however be limited by the flexibility of the SMR unit. It requires hours to re-start the SMR. Moreover, it is not recommended doing so often as the catalyst tubes lifetime is impacted, potentially resulting in permanent damage. As a result, operating the SMR in a start/stop mode in not feasible. Even the possibility of ramping up/down the SMR is limited by the plant technology / design and process control system. When replacing fossil-H_2 by renewable-H_2, the existing control system might be able to manage to balance the production just for a very small % of the change in the feed make-up flow. In most cases, an advanced predictive control system will need to be installed for keeping the main operating parameters within operating constraints without significant production losses. This system will only work if an accurate prediction of the future external hydrogen production is available.

The minimum load of SMR is around 50-60% of the plant's nominal production capacity. Ramping up a load of the SMR plant from 60% to 100% takes about 2-3 hours. Unloading is faster, but usually is connected with disturbances of process parameters, therefore additional hour is needed for stabilization. Moreover, the efficiency of the reforming process decreases in partial load operation. As a result, it is difficult to imagine a hybrid operation where renewable hydrogen share in total hydrogen inputs to the ammonia synthesis loop is higher than 40-50% - if a stable flow of renewable hydrogen is ensured – or significantly less in case of onsite hydrogen production based on variable renewable electricity.

5.3.2. Carbon intensity of ammonia production with hydrogen obtained from water electrolysis

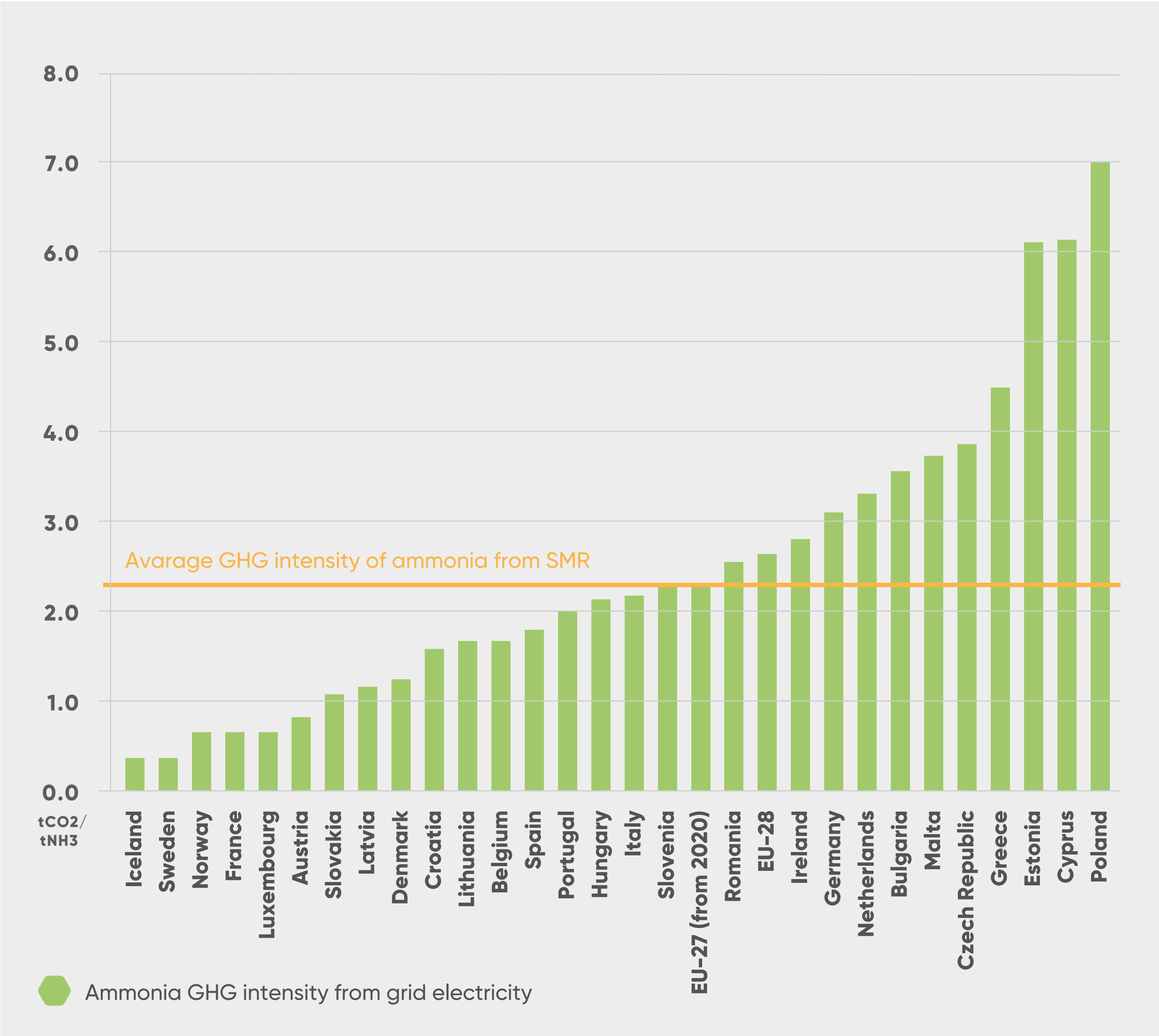
A key feature of an ammonia manufacturing process using hydrogen obtained by water electrolysis is that the process becomes almost completely electrified – **consuming around 9.8 MWh per 1 tonne of ammonia.** As a result, the GHG intensity of ammonia production depends entirely on the carbon intensity of electricity used in the process.

If exclusively renewable electricity is used, the carbon footprint of ammonia can be reduced almost to zero.

On the other hand, if electricity is supplied from the power grid, the final carbon intensity of ammonia production depends on the average carbon-intensity of electricity generation in that grid.

While in most EU countries using grid electricity for hydrogen generation would result in a decrease of total GHG emissions of ammonia production, compared to the SMR route, in all current top three ammonia-producing countries (i.e. DE, NL and PL) the total emissions would increase rather significantly - with the most extreme example being Poland, where reliance on grid electricity would increase emissions by 300%. Assuming the average EU carbon intensity of electricity generation in 2020 of 265 gCO_2/kWh, the resulting ammonia carbon footprint would be equal to 2.6 tCO_2/tNH_3 – i.e. 12% higher than using natural gas (including botch scope 1 and 2 emissions). This underlines the importance of ensuring that either renewable or low-carbon electricity is used for electrolysis as much as possible.

Figure 20: CARBON INTENSITY OF AMMONIA PRODUCTION BASED ON GRID ELECTRICITY IN THE EU IN 2020.
Source: HYDROGEN EUROPE



The need to maximize the use of low-carbon electricity is even more obvious when comparing the resulting ammonia carbon intensity with the threshold defined by the EU taxonomy on sustainable finance. Based on 2020 EEA[26] data, only three countries in Europe (Iceland, Sweden, and Norway) have low enough carbon intensity of grid electricity to enable the production of ammonia within the threshold defined by the EU taxonomy (i.e. using hydrogen with a carbon footprint of 3.0 tCO2e/tH2 or less).

5.3.3. Levelized costs of electricity-based ammonia production

In a fully electrified ammonia production, based on hydrogen produced via water electrolysis, the hydrogen supply costs would be, by far, the dominant cost item, responsible for around 70% of all costs (at 2 EUR/kgH2).

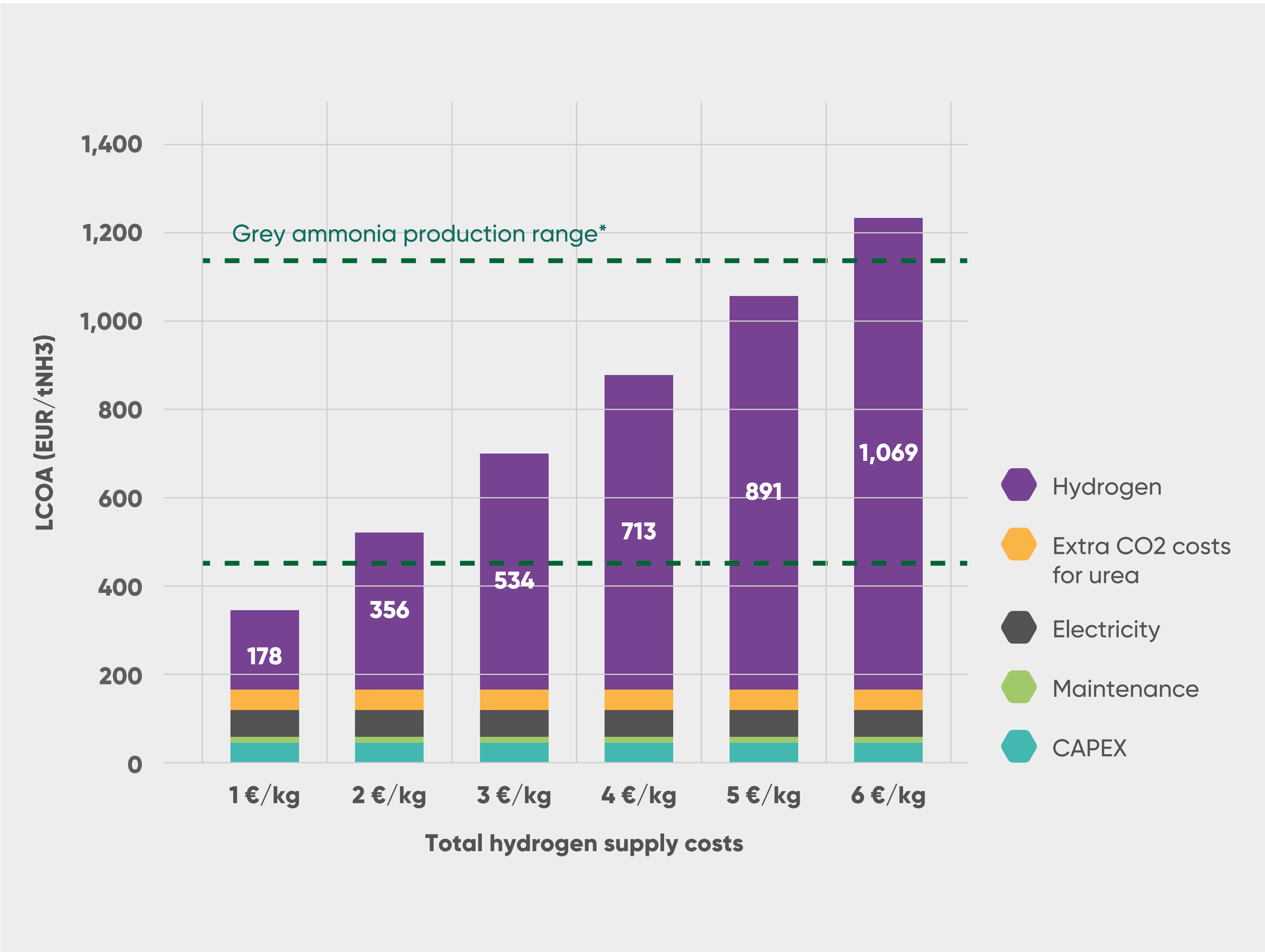
26 / European Environment Agency.

At current high natural gas prices in Europe (110 EUR/MWh) and CO2 emission costs (75 EUR/t) using low carbon or renewable electricity instead of natural gas for ammonia production would be profitable in the bloc even at relatively high hydrogen supply costs of 5.4 EUR/kg. However, with such high production costs ammonia production in the EU would most likely not be competitive with imported ammonia from low-cost gas regions. With natural gas prices of 50 EUR/MWh (2025 price forecast by IEA) the break-even point for renewable hydrogen supply cost would be at around 3.0 EUR/kg.

Such production costs for renewable hydrogen in the EU are still challenging given current electrolyser CAPEX and RES LCOE levels, but are borderline possible in a number of EU Member States.

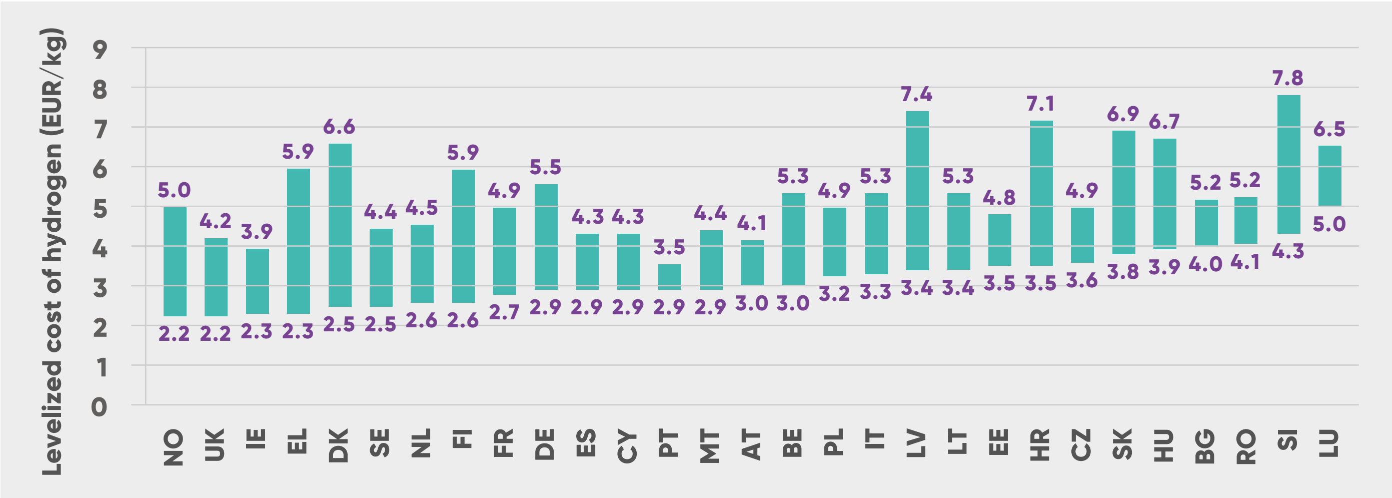
If, however, the natural gas prices were to fall back to their historical level of around 20 EUR/MWh, the pressure for hydrogen supply costs would increase significantly, moving the hydrogen break-even point to around 1.6 EUR/t. Such a low renewable hydrogen production cost would be extremely challenging, if not impossible to achieve today – especially in countries like Poland, Germany and Netherlands (top three ammonia producers in the EU), with relatively poor solar irradiation and average wind conditions.

Figure 21: LCOA FOR GREEN AMMONIA DEPENDING ON RENEWABLE HYDROGEN SUPPLY COSTS.
Source: HYDROGEN EUROPE.



Note: Grey ammonia production range estimated for CO2 cost of 75 EUR/t and natural gas cost range between 20 EUR/MWh and 110 EUR/MWh.

Figure 22: LEVELIZED COST OF ELECTROLYTIC HYDROGEN DIRECTLY CONNECTED TO RES.
Source: HYDROGEN EUROPE.



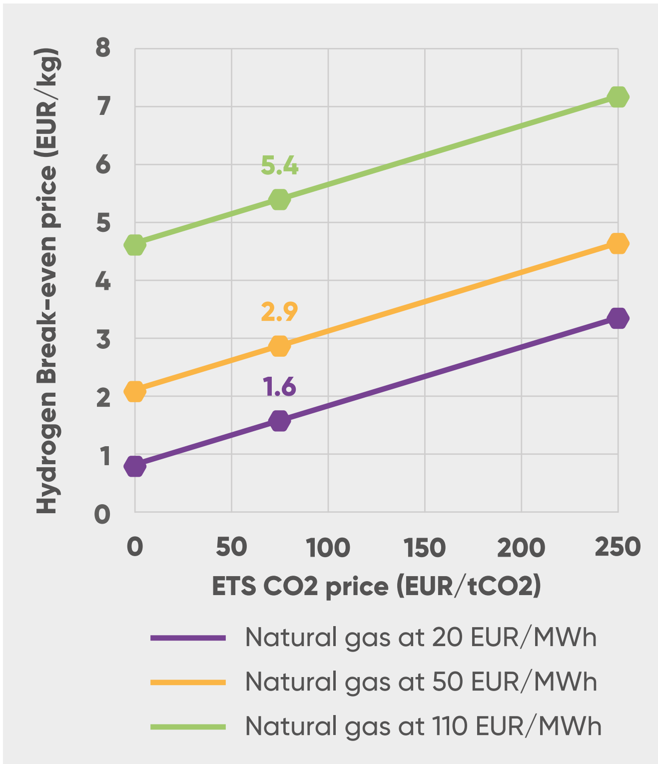
Note: The upper end of the range depicts levelized costs of hydrogen produced using average solar irradiation or wind conditions in a given country and the lower end depicts levelized costs of hydrogen produced using best available solar irradiation or wind conditions in a given country (whichever technology is cheapest).

It should also be highlighted that the above break-even point values include all costs related to the hydrogen supply. Therefore, if hydrogen was to be produced off-site or imported and delivered via pipelines – all those additional costs would have to be covered as well. Similarly, for on-site production, grid connection fees as well as potential additional costs of RED II/III compliance would have to be also factored in, further increasing pressure on hydrogen production costs.

This means that if natural gas prices start to fall, renewable ammonia production, in order to break even, would either require a green market premium to be paid by the end consumers or a significant increase of CO2 costs. Assuming hydrogen delivery cost at 3 EUR/kg and natural gas prices at 20 EUR/MWh, the required EU ETS CO2 emission price would however be as high as 216 EUR/tCO2. This clearly demonstrates how important it is that the EU policy for renewable hydrogen is focused not only on the upstream part of the ammonia value chain but includes also on the downstream part. Without creating a demand for renewable ammonia-based products, the business case for investing in new green ammonia facilities will be jeopardized.

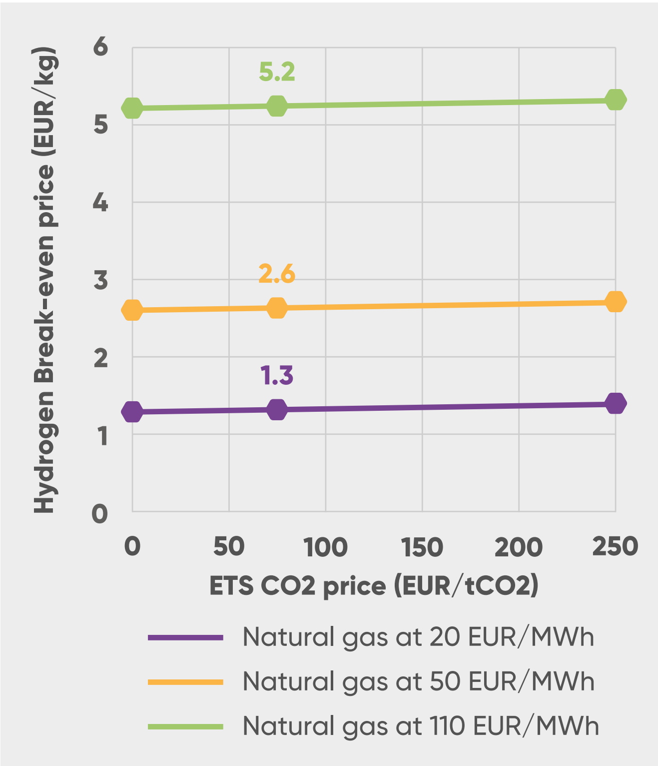
It should be noted however that the increase of CO2 prices would impact the relative cost competitiveness of renewable

Figure 23: RENEWABLE HYDROGEN DELIVERY COST BREAK-EVEN POINT FOR AMMONIA PRODUCTION, COMPARED TO GREY AMMONIA, DEPENDING ON NATURAL GAS AND CO2 PRICE.
Source: HYDROGEN EUROPE.



hydrogen only in comparison to the grey ammonia production pathway. But compared to blue ammonia – especially blue ammonia produced via the ATR+CCS pathway with close to 100% direct emission avoidance – the renewable hydrogen option is even less competitive – as the CO2 prices have no impact.

Figure 24: RENEWABLE HYDROGEN DELIVERY COST BREAK-EVEN POINT FOR AMMONIA PRODUCTION, COMPARED TO BLUE AMMONIA, DEPENDING ON NATURAL GAS AND CO2 PRICE.
Source: HYDROGEN EUROPE.



One additional important point to take into account is that the above cost analysis is based on an assumption of a steady supply of hydrogen to the Haber-Bosch synthesis loop throughout the year, allowing for a 95% capacity utilization. While this is possible for both grey and blue ammonia production based on natural gas, for electrolytic hydrogen – especially if variable renewable energy sources are used exclusively as the power source - this will be another challenge, further impacting the cost competitiveness of renewable ammonia (see below for further information).

5.3.4. Supply of renewable hydrogen

Assuming an average-sized ammonia plant with a capacity of around 500kt of ammonia per year and a demand for hydrogen of 11 tonnes per hour, hydrogen generation alone would require around 8.5 MWh per tonne of NH3 produced or a total of 4.8 TWh/y for an average plant. Converting all the current ammonia production in Europe into green ammonia would require 2.5 Mt of renewable hydrogen and close to 130 TWh of renewable electricity (including the UK).

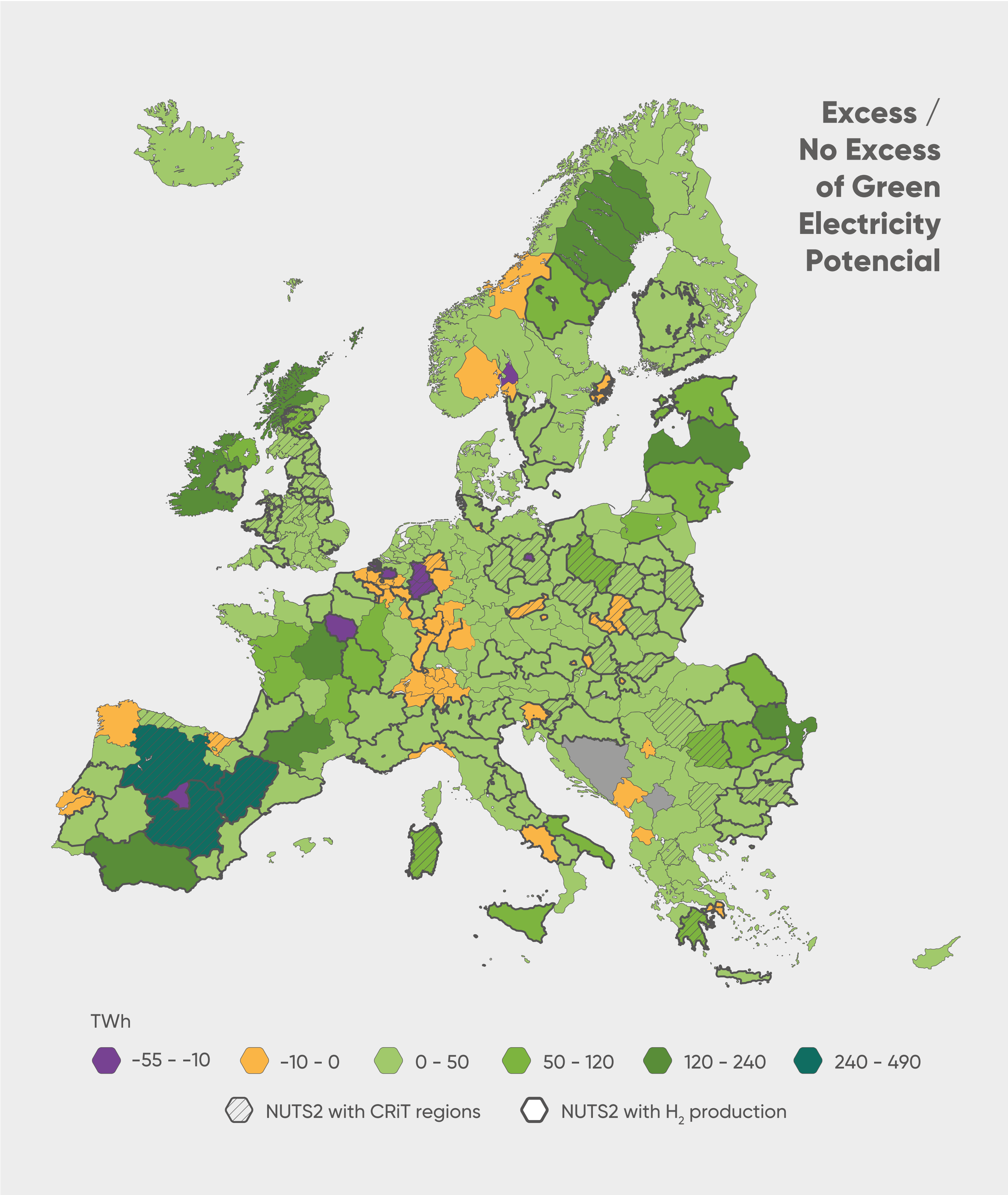
This is clearly a challenge – especially noticing that the bulk of ammonia production is located in countries where low-cost renewables are not abundantly available (e.g., Belgium).

According to an analysis from the JRC, there are 13 EU regions (NUTS-2 level) where the renewable energy potential is insufficient to cover expected electricity consumption including demand for electrolytic hydrogen generation. The regions of the EU with the highest electricity and hydrogen demand are located mostly in industrial areas in the northern part of the continent (Benelux, Ruhr Valley, South of Germany, South of Poland).

In reality however, the problem is even more acute. The analysis includes only existing uses for hydrogen and excludes potential new applications like, the steel sector, which will require significant amounts of renewable hydrogen as well, and which are also, to a large extent, located also in countries with a potential shortage of renewables. Furthermore, the existence of technical potential does not mean that the economic conditions would be sufficient for all those renewable sources to be developed at a price that would allow the production of renewable hydrogen at a cost-competitive level. Another issue is the time required to develop those renewable assets, further exacerbated by the fact that in some countries significant new RES deployment is still needed for the purpose of power grid decarbonisation, limiting access to new RES for hydrogen projects.

As an example – in order to entirely decarbonise ammonia production with renewable hydrogen in Poland, almost 400kt of renewable hydrogen and, by extension, almost 20 TWh

Figure 25: BALANCE OF RENEWABLE ELECTRICITY POTENTIAL
Source: JOINT RESEARCH CENTRE.



of renewable electricity would be needed. For reference, the current Polish national energy policy plan, envisages that all new solar PV, onshore and offshore wind assets, developed between 2020-2030 will be able to generate 19.6 TWh of additional renewable electricity by the year 2030. In other words, full decarbonisation of ammonia production in Poland would require more additional renewable energy than will be deployed in the entire country by the end of this decade – and Poland is still going to require that renewable electricity to reduce its reliance on coal-fired power plants (56% of planned power generation in 2030). Even though the proposed renewable energy directive will most likely only require to replace 40-50% of grey hydrogen with renewable one by 2030, it will undoubtedly remain a huge challenge in some EU Member States – further exacerbated if a strict approach to renewable energy additionality requirement is adopted.

Another challenge related to the supply of renewable hydrogen is related to variability and intermittency of renewable energy generation which might result in a need for high-capacity hydrogen storage. The Haber-Bosch process is autothermic, which means that the heat of the reaction is normally sufficient if well-exchanged to the inlet stream. If the inlet stream is not sufficiently heated, however, the rate of reaction will drop, lowering the amount of heat available, which in turn lowers the inlet temperature even more and can stop the reaction completely. For the normal operation at 200 bar, the feed must enter at around 400ºC. For lower temperatures, the reaction will not be able to produce sufficient heat to maintain the reaction. The heat management complexity of the process, allied with the need to recycle the reactants in multiple loops in order to reach the desired conversion rate, poses some challenges to the flexibility of the system.

If the ammonia plant would be composed of multiple Haber-Bosch reactors, the temporary shut-down of one or two reactors in the system would be possible when the hydrogen supply is not sufficient. Most existing plants, however, are composed of only one Haber-Bosch reactor.

In principle, the ramp-up/down rate of the ammonia synthesis unit may be generally done in a relatively short time. As long as the temperature profile does not significantly change, 90% reduction in load (i.e. from 100% to 10% load) can be done in 1 hour. In practice however, the efficiency of the process starts drastically decreasing below 70% load. As energy consumption represents >85% of the production cost of ammonia, even minor losses of efficiency (e.g. even when operating below 90% load) can destroy the profitability and competitiveness of the production plant - unless fully compensated by a significantly lower power price or unless such a reduction is a rare event.

The technical minimum load for Haber-Bosch is around 30-40% which should be considered when designing the hydrogen storage for avoiding a full shutdown and restart cycles – although depending on individual conditions and the level of integration of the ammonia plant into the wider industrial setting it is located in, in some cases, it might not be practical to reduce the load below 50-60%. In addition, the start/stop of a Haber-Bosch unit is technically not advisable as well as being very costly (~1M USD) because of the unproductive use of natural gas during the start-up and shutdown phases - when no ammonia is produced.

The optimal strategy to deal with the minimum operational load requirements for the Haber-Bosch unit would depend on the way hydrogen supplies are organised.

Renewable hydrogen could be produced remotely, directly connected to the renewable energy assets and then supplied to the ammonia production site via pipeline. Such decentralized renewable hydrogen generation has the disadvantage of low full load hours per year, a discontinuous production, and the need for an energy storage system – especially if that hydrogen is to be delivered to an industrial off-taker, like an ammonia plant, requiring steady delivery. On the other hand, decoupling hydrogen production and consumption allows to produce hydrogen in optimal locations and alleviates the issue of insufficient local renewable energy availability.

The second possibility is onsite hydrogen production integrated with the ammonia plant, based on a PPA contract for the supply of green electricity. As the PPA alone will not, most likely, ensure a continuous supply of electricity, to ensure a constant supply of hydrogen, either the PPA needs to be supplemented with grid electricity or additional costs for hydrogen storage need to be considered. While hydrogen transportation costs would be avoided in this case, additional electricity network fees and taxes would increase hydrogen production costs. Furthermore, as a large ammonia plant would require grid connection on a GW-scale, it could potentially have a negative impact on local grid congestion. Since grid electricity in most of the countries in Europe will not be free of emissions, the necessity to rely on it to stabilise hydrogen flow might also limit the climate change mitigation benefits of the investment.

5.3.5. Off-site hydrogen generation

In the case of direct connection to a renewable source of energy, the required installed capacity will greatly depend on the renewable source and the country of deployment, as these criteria greatly affect the capacity factor and, consequently, the total hydrogen output.

Assuming a typical ammonia plant with a capacity of 500kt of ammonia per year, requiring around 11 tonnes of hydrogen per hour, if the renewable energy assets would be located in North-Western Europe, where most of the ammonia production currently takes place, up to 5 GW of new solar PV would be needed, to produce the required renewable energy. If wind energy was to be used, the installed capacity needed would be 1.3 GW or 1.9 GW for offshore and onshore wind respectively. Since the output from RES assets, at such a scale, is rarely 100%, the required capacity of electrolysis would be smaller, but it would still be between 3.9 – 1.2 GW (for a single ammonia plant).

The amount of required hydrogen storage – needed to ensure a steady flow of hydrogen throughout the year - would also heavily depend on the chosen RES electricity mix. If the power supply would be based exclusively on solar PV, the storage would have to have a capacity equal to as much as 21% of annual hydrogen output. On the other hand, for offshore wind, the storage needs would fall to around 15% of annual output. However, since seasonal energy generation from solar and wind are, to some extent, negatively correlated, for a combination of wind and solar, the required storage capacity could be reduced to below 8% of annual hydrogen needs.

Figure 26: RENEWABLE ENERGY AND ELECTROLYSER CAPACITY TO FULFIL THE AVERAGE PLANT'S DEMAND.

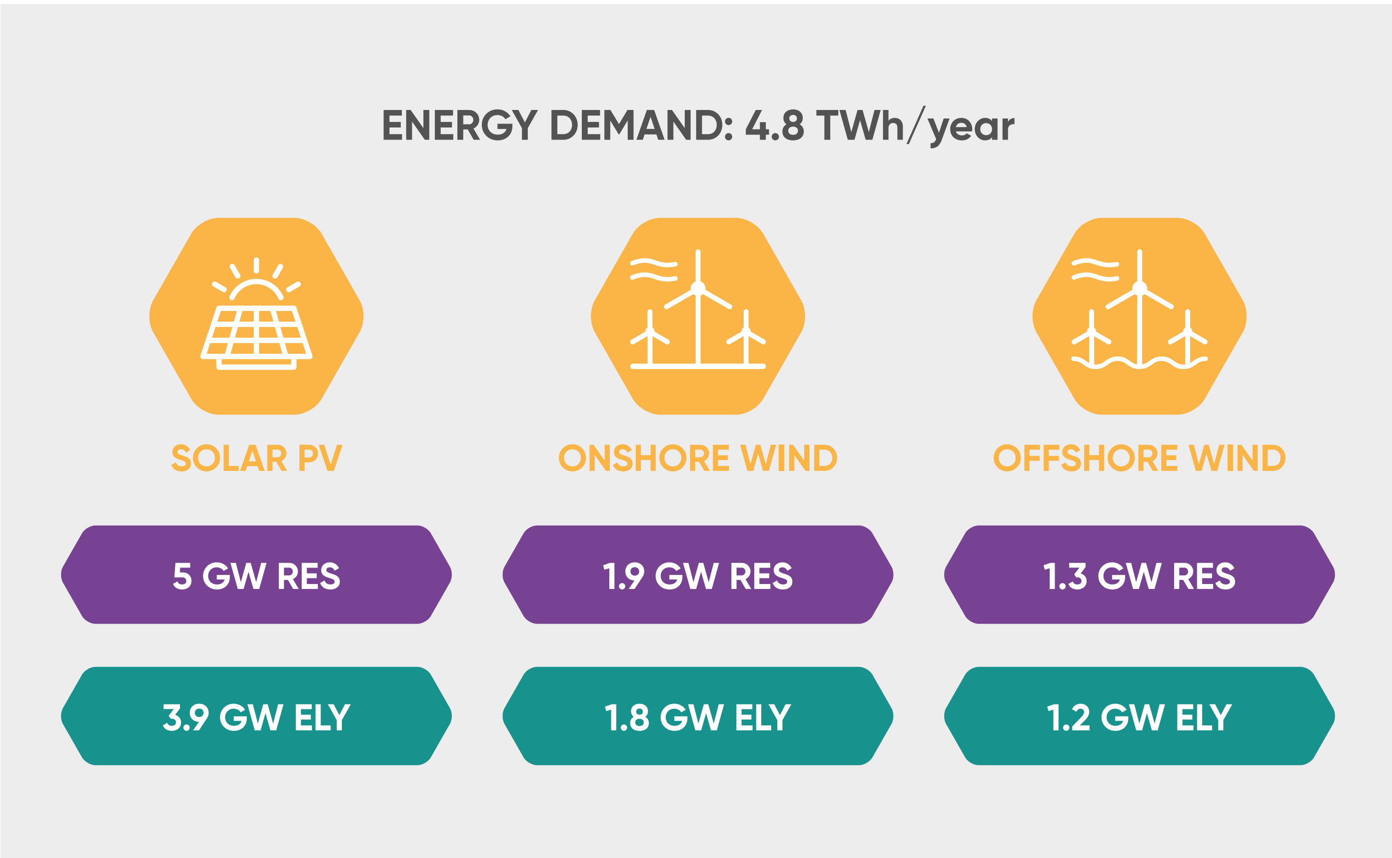
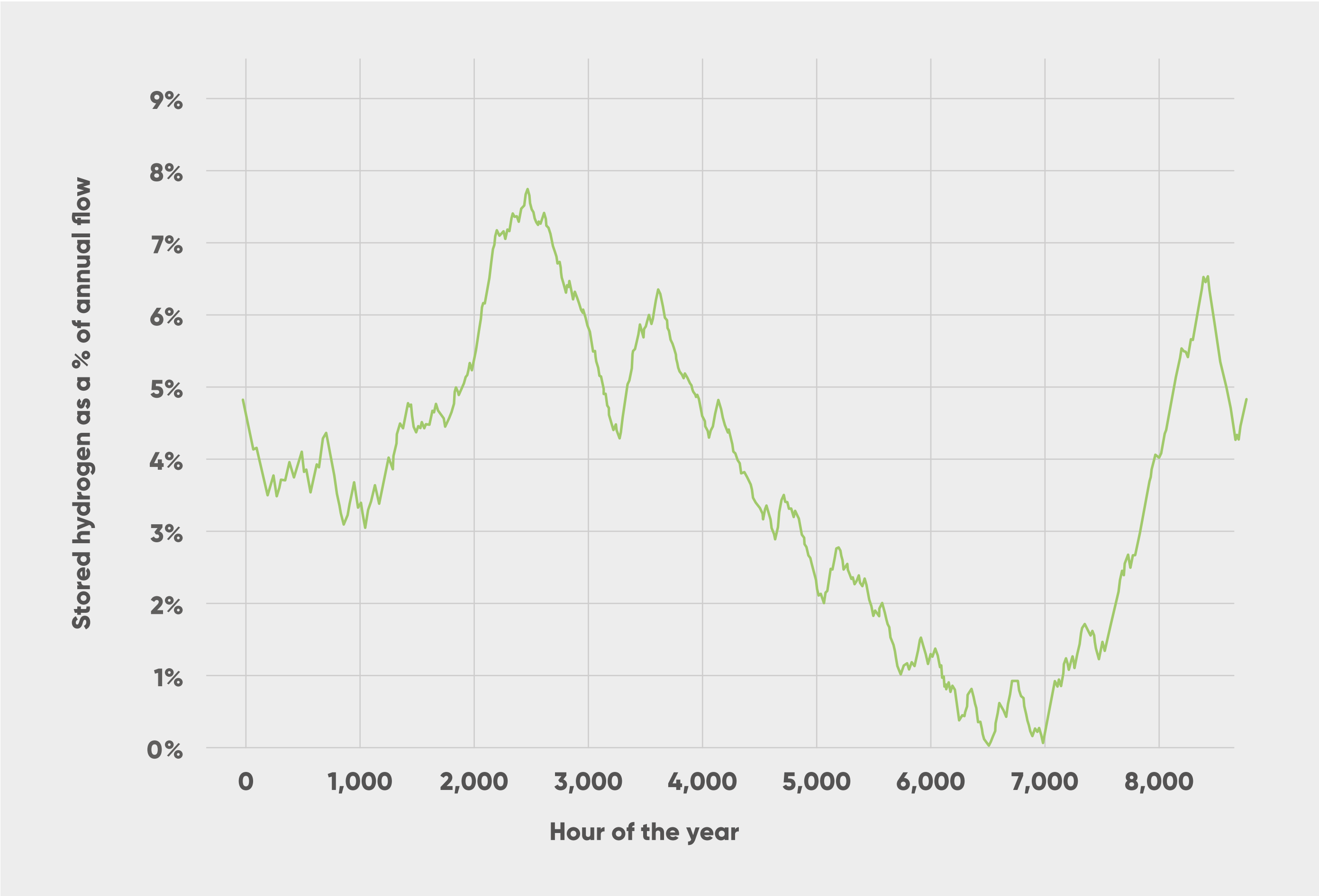


Figure 27: ESTIMATED AMOUNT OF STORAGE NEEDED THROUGHOUT THE YEAR TO ENSURE STEADY FLOW OF HYDROGEN IF THE SUPPLY IS BASED ON 50/50 MIX OF SOLAR PV AND OFFSHORE WIND.
Source: HYDROGEN EUROPE.

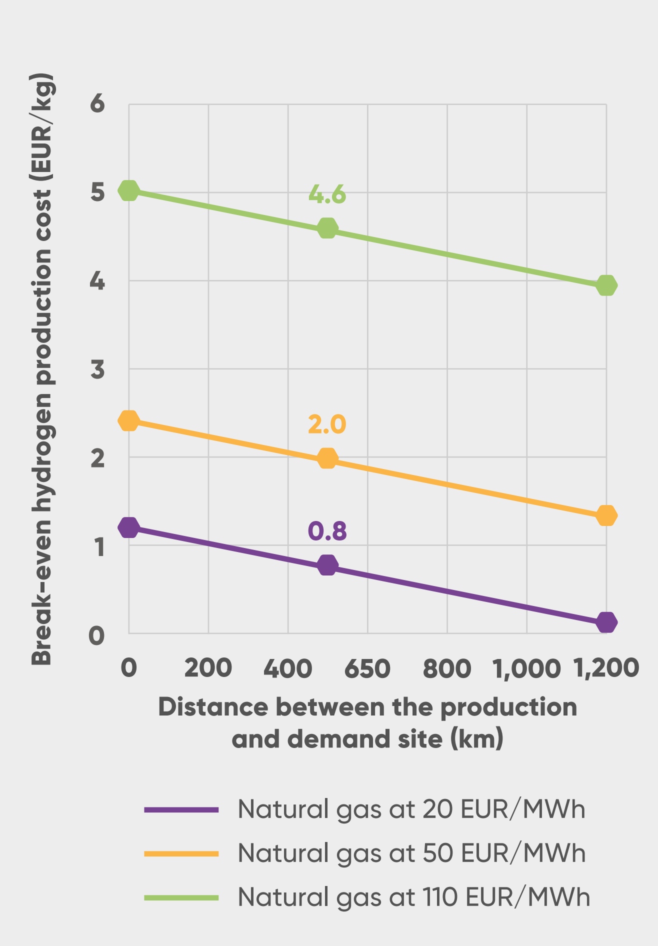


For an ammonia plant of the assumed size (500 ktpa), that would mean a storage requirement of close to 7,000 tonnes of hydrogen. Assuming a salt cavern as a storage solution, it would require additional CAPEX of around 250M EUR and would increase the cost of hydrogen by around 0.3 EUR/kg. It should be noted however, that, while underground hydrogen storage in salt caverns offers a cost-effective solution, underground salt formations are not uniformly available across the whole EU.

Furthermore, hydrogen would have to be transported from its remote production site to the underground storage facility and to the ammonia plant. Given the amounts of hydrogen to be transported inland, the only viable option would be hydrogen pipelines. Assuming a 500 km transport distance in total, the estimated transport costs of hydrogen would be around 0.5 EUR/kg.

Together the transportation and storage costs would add further pressure on the hydrogen production costs. As previously estimated, assuming the historical level of natural gas cost at 20 EUR/MWh, the break-even cost of hydrogen supply was 1.6 EUR/kg. Therefore, for an off-site hydrogen production scenario, including the estimated transport and storage costs, it would mean that the pure renewable hydrogen production costs could not exceed 0.8 EUR/kg. If future natural gas costs were to settle at 50 EUR/MWh (IEA forecast for 2025), the hydrogen production costs would be 2.0 EUR/kg and at current natural gas prices – 4.6 EUR/kg.

Figure 28: ESTIMATED HYDROGEN PRODUCTION BREAK-EVEN POINT DEPENDING ON NATURAL GAS PRICE AND DISTANCE FROM DEMAND SITE.
Source: HYDROGEN EUROPE.



5.3.6. Grid connected plant scenario

While electrolyser direct connection removes additional costs from grid fees and makes the renewable nature of hydrogen easy to prove, it also comes with significant disadvantages – the most obvious ones being lower electrolyser capacity factor and the need to transport the hydrogen from production to consumption site.

Onsite hydrogen production from electricity delivered via the power grid allows for the mixing of multiple sources of renewable energy via multiple PPAs and can therefore help reduce the intermittency of energy supply and increase the electrolyser capacity utilization and reduce investment needs. No long-distance hydrogen transportation is necessary either.

In the previous example of electrolysis directly connected to renewable energy the electrolyser capacity has been estimated at 3.9 – 1.2 GW, depending on RES technology. Local, on-site hydrogen production at full load, would enable to produce the same amount of hydrogen with only 550 MW. With electrolyser CAPEX at 600 EUR/kW, it could reduce needed investments by up to 2 billion EUR.

On the other hand – it would require careful management of the electrolyser energy supply, to maximize its utilization but at the same time make sure that the average carbon intensity of used electricity allows for significant decarbonisation, which should be the main objective. Assuming electricity will be sourced from a variety of PPAs with a mix of 40% solar PV and 60% wind, one could imagine two extreme approaches to the power management issue (with anything in-between possible as well):

- **Match peak demand:** Contracting only as many renewable PPAs that at their maximum output the generated energy is equal to the electrolyser's rated capacity, i.e. there is never more electricity being produced from the contracted renewable sources than the amount needed from the electrolyser and no curtailment or export of electricity is needed. In this example, this could mean 280 MW of solar PV and 420 MW off-shore wind.

- **Match annual demand:** in this approach, the RES capacity contracted is oversized to an extent which would ensure that over the duration of the year, total output of those renewable assets would be equal to the annual consumption of electricity from the electrolyser running at full load. To achieve such an objective 750 MW of solar PV and 1,170 MW of offshore wind would have to be contracted. While the amount of fully renewable electricity is higher in this scenario, there is also excess renewable energy generation which would have to be exported to the grid or used for other demands from the ammonia plant.

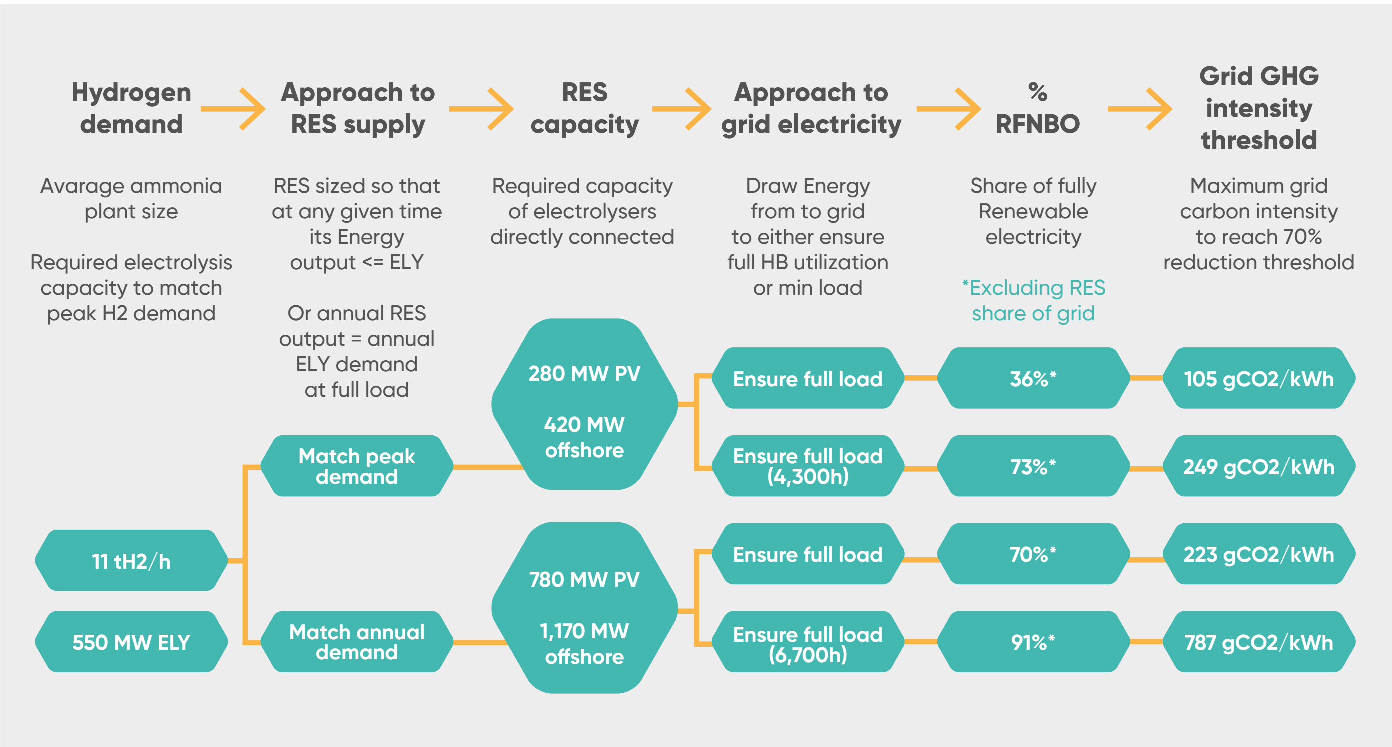
Furthermore, in both scenarios, the ammonia plant operator could choose to use grid electricity at all times whenever the combined output from all contracted RES is below the rated power of the electrolyser – and thus ensure its full utilization. Alternatively, grid electricity consumption could be restricted – to only ensure that the hydrogen output would be just sufficient to make sure the load of the Haber-Bosch reactor does not fall below the minimum 30-40%. The latter would limit the share of grid mix electricity and improve the carbon footprint of hydrogen (and ammonia), but would inevitably lead to a reduction of annual hydrogen and ammonia production. In the "match peak demand" approach, this would reduce the ammonia output by more than 50%. Even in the "match annual demand" approach, the total output would fall by 1/3.

Another key element to consider would be the total renewable energy share in energy consumed for hydrogen production. In theory, respecting the "match annual demand" approach could ensure that 100% of the hydrogen produced can be considered renewable. Even if there are times when not enough renewable energy is being produced and the electrolyser is being fed by the grid mix, this would later be compensated by the times that the PPA is producing more green electricity than the one that the electrolyser is demanding. In practice, however, this approach is likely to be restricted by the regulatory framework – requiring some level of temporal correlation between renewable energy generation and hydrogen production.

Finally, the use of grid electricity would impact the overall carbon footprint of hydrogen and ammonia produced. To be recognised as a renewable fuel of non-biological origin (RFNBO) the total carbon footprint needs to be at 70% lower that the fossil fuel comparator of 94 gCO2e/MJ, i.e. at most 28.2 gCO2e/MJ.

In order to ensure that the threshold is met, the more grid electricity is used the lower its average carbon intensity would need to be. In the scenario of RES overcapacity coupled with using grid electricity only if necessary, the total share of renewable power would be higher than 91%, allowing for the electricity to have as high a carbon footprint as 787 gCO2/kWh. On the other end of the spectrum, if the amount of contracted renewable energy would only cover the peak demand but the electrolyser would still be run at full capacity, the average carbon footprint of electricity would have to be as low as 105 gCO2/kWh, which is possible only in a very limited number of EU Member States. As the exact details of the regulatory framework defining the conditions for fuels to be recognised as RFNBO as still not finalized, the above analysis should be regarded as illustrative only.

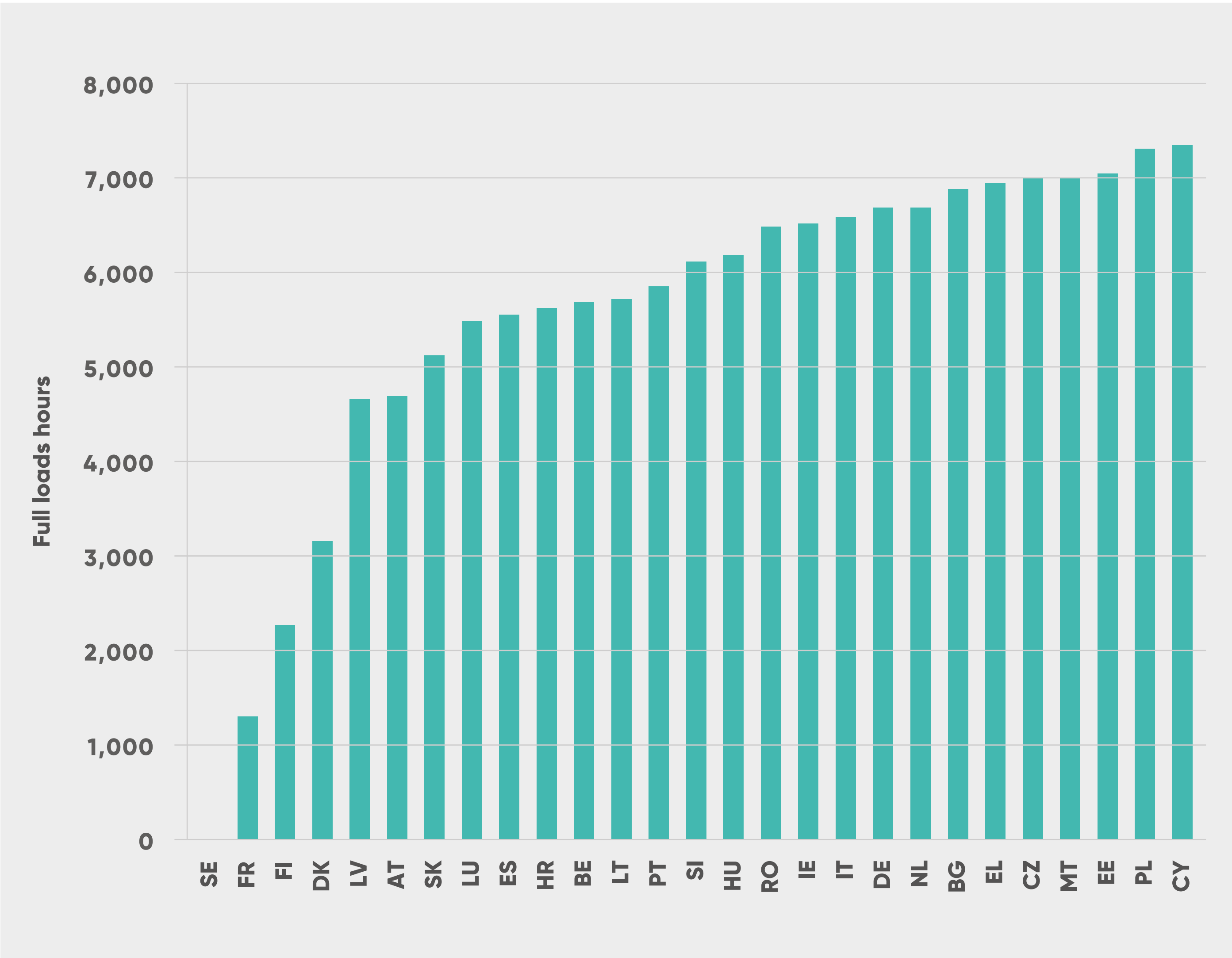
Figure 29: POWER MANAGEMENT CONSIDERATIONS FOR ON-SITE HYDROGEN PRODUCTION.
Source: HYDROGEN EUROPE.



The above considerations would reduce the possibility to rely on grid electricity in countries with high average carbon intensity – as the average carbon footprint of produced fuel could fail to reach the required GHG reduction threshold. In other words, in countries like Poland, with its high share of coal-based electricity in the generation mix, most of the electricity consumed for electrolysers would have to be covered by the renewable PPAs. If the end product is ammonia, given the inefficiencies of the production process, clearing the 70% threshold with the use of grid electricity would be even more challenging than for hydrogen only. We estimate that in order to ensure full capacity utilization of an electrolyser (8,000 hours full load equivalent) and, at the same time, be able to produce ammonia at below the required carbon footprint, an ammonia plant in Poland would have to ensure that PPAs supplying fully renewable electricity cover more than 7,300 full load hours of the electrolyser (more than 92% of all electricity consumption).

In Germany and the Netherlands (other major manufacturers), the required amount would be at least 6,700 hours. Whereas in France, due to the low carbon intensity of the grid (thanks to a high share of nuclear energy) or Sweden, grid electricity could be used almost without any limits.

Figure 30: MINIMUM PPA COVERAGE FOR AN ELECTROLYSER IN ORDER TO REACH THE 70% GHG REDUCTION THRESHOLD FOR GREEN AMMONIA, ASSUMING 8,000 FULL LOAD HOURS CAPACITY FACTOR OF THE ELECTROLYSER
Source: HYDROGEN EUROPE.



5.3.7. Example green ammonia project

Over 20 renewable and low-carbon ammonia projects have already been announced in Europe to be online in 2030, foreseeing partnerships between different ammonia and fertilizer manufacturers and hydrogen suppliers, including big stakeholders like Yara, Fertiberia, Iberdrola, Hyperion, Siemens, Orsted, and others.

Fertiberia's ammonia plant in Puertollano is the first green ammonia plant in Spain, inaugurated in May 2022. In partnership with Iberdrola, a 100 MW PV facility was installed on-site to produce the green electricity required to power the 20 PEM MW electrolyser. A dedicated underground line connects the two, to ensure that all energy used in the electrolyser is fully renewable. The facility has the capacity to produce 360 kg of hydrogen per hour or 3,000 tonnes of hydrogen annually and the potential to avoid 39,000 tonnes of CO2.

Solar radiation intermittency is handled both with battery electrochemical storage and hydrogen storage. The system has an integrated 5 MW/20 MWh lithium-ion battery, which is enough to cover one hour of hydrogen production at full capacity. In addition to stabilizing the electricity supply, the electrochemical storage allows for greater flexibility and optimization of control strategies. The hydrogen storage system has a capacity allowing for the storage of 6,000 kg of renewable hydrogen, equivalent to around 16 hours of hydrogen output at capacity, which is enough to ensure the required feedstock availability for the Haber-Bosch plant needed during low solar irradiation hours.

The PV installation incorporates state-of-the-art technologies, such as bifacial panels, which allow for higher production by having two light-sensitive surfaces, and string inverters, which improve performance and make better use of the surface area. The installed PV to Electrolyser capacity ratio of 5:1, allows the operator to ensure that the electrolyser runs on a nominal capacity for longer periods of time, optimizing its utilization. Whenever there is a surplus of energy generation, the electricity can be used to refill the storage systems or exported to the electricity distribution network. A total of 150 million EUR were invested in the project.

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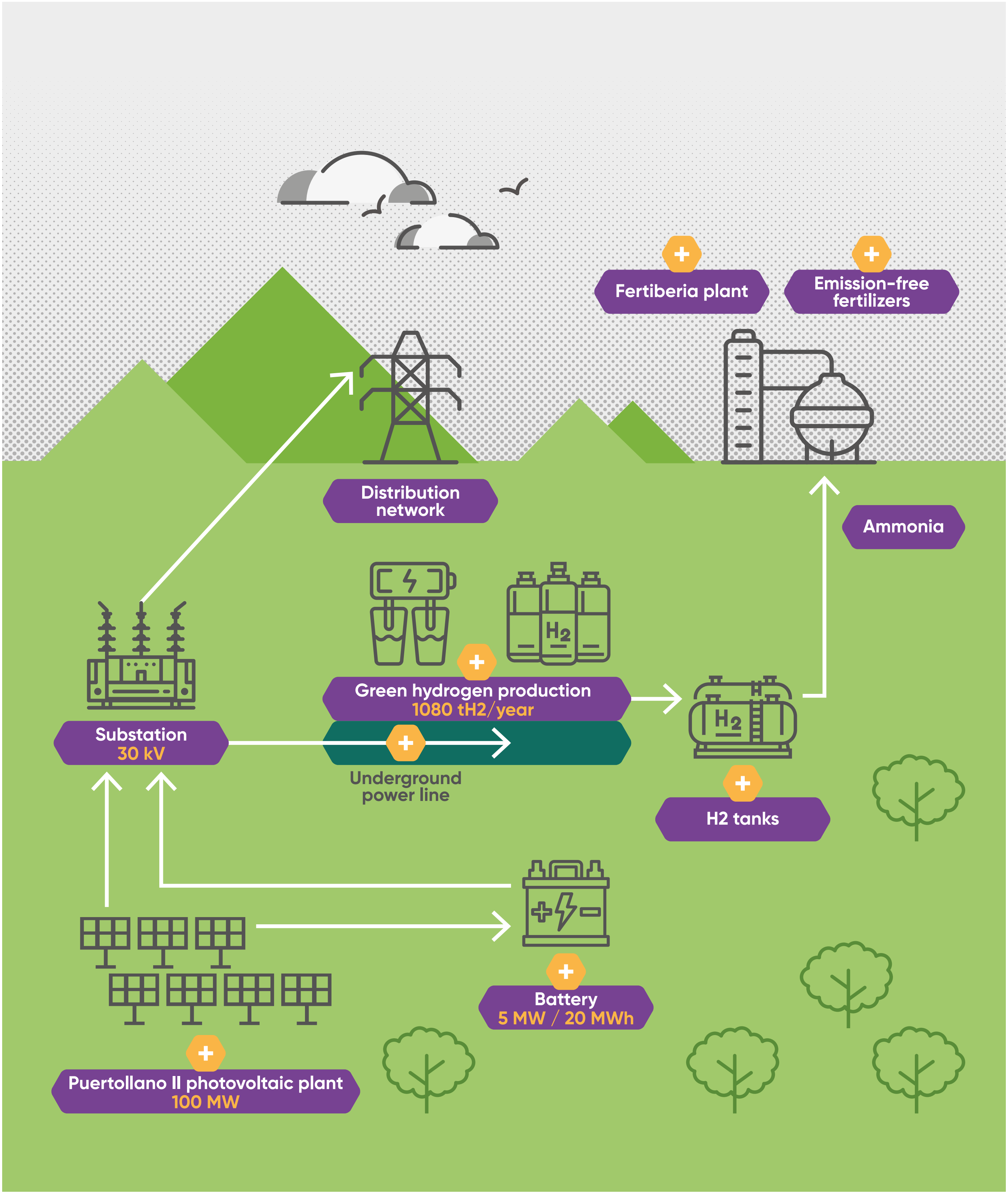
Figure 31: PUERTOLLANO AMMONIA PLANT SCHEMATIC.
Source: IBERDROLA.



06

Emerging new applications for ammonia

Currently, ammonia is mostly used as feedstock for the production of fertilizers or other chemicals. As demonstrated in the previous chapter, replacing the current production methods based on natural gas with renewable ammonia will be challenging at current green ammonia production costs - especially if natural gas prices start to fall. A persisting green ammonia production cost gap, combined with RED targets for the use of renewable hydrogen in the industry will create a risk that, instead of switching to renewable hydrogen, the ammonia industry might opt for imports of ammonia.

By importing clean ammonia as an RFNBO and using it as a feedstock in the production of fertilisers, the Member State reduces its absolute in-house RFNBO production needs. In this situation, the target is more easily met not only because the domestic consumption of hydrogen decreases (decreasing the denominator component of the target) but also because the amount of RFBNO used in the country's industry increases (increasing the numerator component of the target). Much will however depend on the way the regulations are transposed into national regulations and whether the targets will be applied on plant-by-plant basis or more broadly to entire industry.

On the other hand, as imports of grey ammonia would allow to circumvent the targets altogether[27], with little incentives for ammonia and fertilizer end users to cover the cost gap by paying a green premium, importing grey ammonia would, in many cases in Europe, be a financially better choice than to comply with RED targets, depending, of course, on how imported CO2 emissions are taxed through CBAM. This would not only result in carbon leakage but also jeopardise thousands of jobs.

There are however a number of emerging new potential applications for green ammonia which could create an additional market beyond the use of ammonia as a fertilizer, thus creating an additional incentive to retain ammonia production in the EU. The most promising new applications include:

1. **Use of ammonia as an energy carrier to facilitate international trade for renewable energy.**
2. **Power generation and energy storage based on renewable ammonia.**
3. **Use of ammonia as an alternative fuel – with the most promising market being international shipping.**

6.1. Ammonia as an energy carrier

To reach global ambitions of transitioning into a carbon-neutral economy by 2050, appropriate green energy storage becomes more and more important and clean ammonia rises in interest not only as a feedstock for the production of fertilisers or other chemicals but also as an energy or hydrogen carrier.

Affordable and efficient An expected increase in hydrogen demand and geographical imbalances related to access to abundant quantities and low-cost renewable energy will facilitate large-scale international trade for hydrogen and its derivatives. To facilitate these exports, import mechanisms such as H2 Global, import facilitators such as the Global European Hydrogen Facility, and agreements such as Memoranda of Understanding (MoU) between importing and exporting countries or individual companies, including ports, were established. From the European perspective, the importance of imports has been underpinned by the RePowerEU target to import into the European Union (EU) at least 10 Mt/y of renewable hydrogen annually by 2030. Hydrogen transport infrastructure will therefore play a crucial role in developing the hydrogen economy.

There are of course many ways of importing renewable hydrogen. For importing hydrogen from the EU close neighbourhood and distances of up to 2-4,000 km, the cheapest option is hydrogen pipelines (with the final comparative advantage of pipelines depending on the type and diameter of the H2 pipeline as well as its average capacity utilization). Without the need for any complex chemical processes, the cost of transporting hydrogen via pipelines can be as low as 0.2 EUR/kg/1,000 km, which can be further reduced to 0.11 EUR/kg/1,000 km by retrofitting existing natural gas pipelines (Guidehouse, 2022).

27 / Import and subsequent use of 'grey' ammonia by the fertilizer industry, instead of self-production of grey ammonia from natural gas with hydrogen as intermediate product, will lowers the denominator component of the RED II targets.

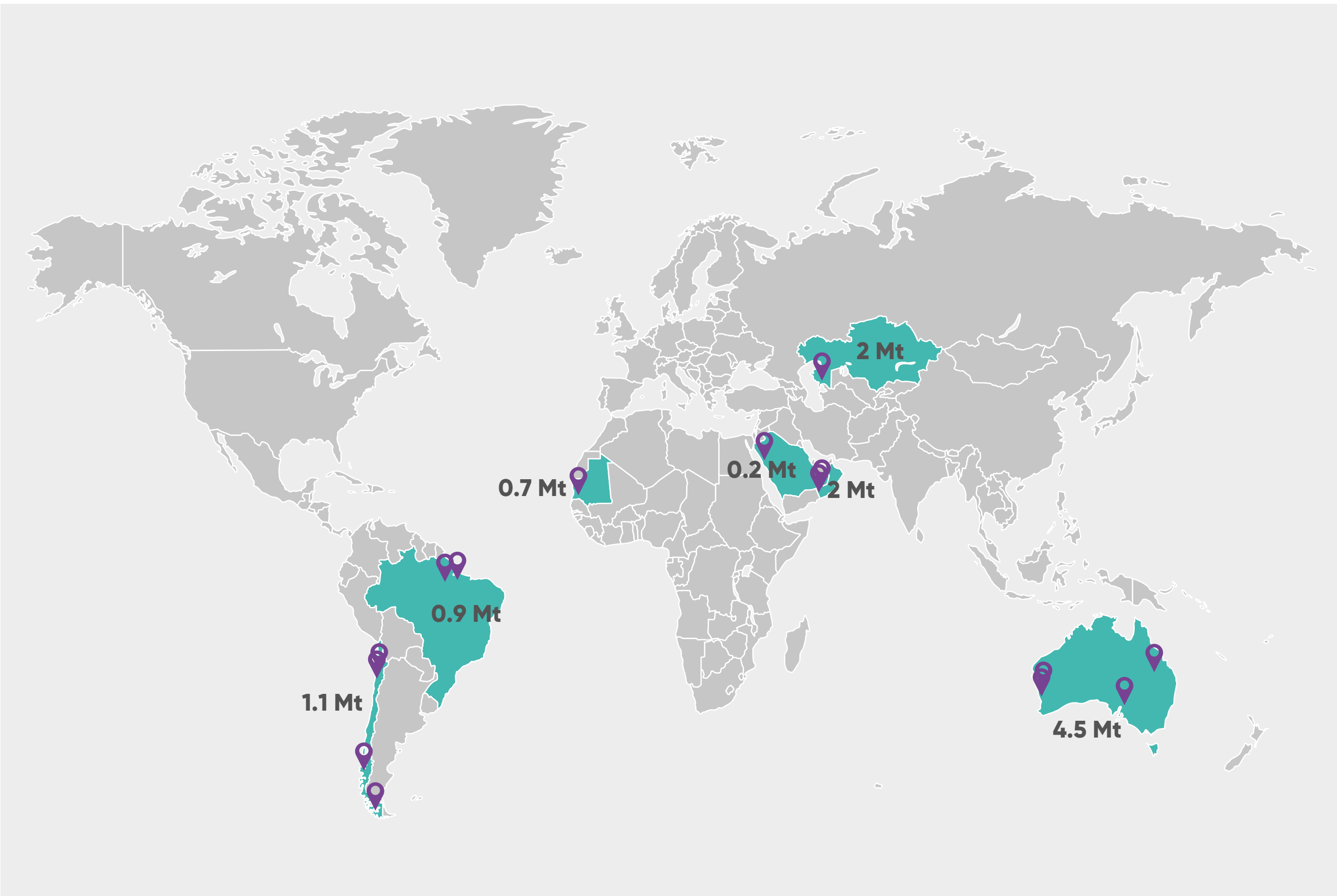
However, the largest – export-oriented - green hydrogen projects worldwide are all located in countries from which imports by pipeline would be either impossible or extremely challenging due to the distances involved. The world's largest export-oriented projects (with over 1 GW of electrolyser capacity) with the potential to deliver to Europe amount to some 11.5 Mt/y of renewable hydrogen equivalent spread over 15 projects. Large export-oriented clean hydrogen projects are mostly located in regions with significant renewable energy potential and close to ports to facilitate exports. The most ambitious plans are being developed in Australia with ~4.5 Mt/y of hydrogen for exports. Kazakhstan and Oman follow with 2 Mt/y of hydrogen for exports each. Chile's projects account for another 1 Mt/y of hydrogen. Announced projects in Brazil, Mauritania, and Saudi Arabia should also produce slightly less than 1 Mt/y of hydrogen for exports in each country.

If pipelines are not an option, hydrogen could be exported by ships. Due to a relatively low volumetric energy density of compressed hydrogen however, the most promising options require either hydrogen liquefaction or the use of other substances, like ammonia, as hydrogen carriers.

Liquified hydrogen has many benefits but the lack of existing infrastructure and carrier fleet combined with a necessity for further technological improvements, are making LH2 more of a long-term potential option.

Liquid hydrogen carriers and liquid organic hydrogen carriers (LHC/ LOHCs) are another potential interesting alternatives. These include a slate of different (most often organic) compounds which can absorb and release hydrogen through a chemical reaction. LHCs & LOHCs can serve as a storage and transportation medium for hydrogen

Figure 32: GEOGRAPHICAL DISTRIBUTION OF HYDROGEN EQUIVALENT (IN MT/YEAR) PRODUCED IN SELECTED EXPORT-ORIENTED PROJECTS WITH OVER 1 GW OF ELECTROLYSIS CAPACITY.
Source: HYDROGEN EUROPE.

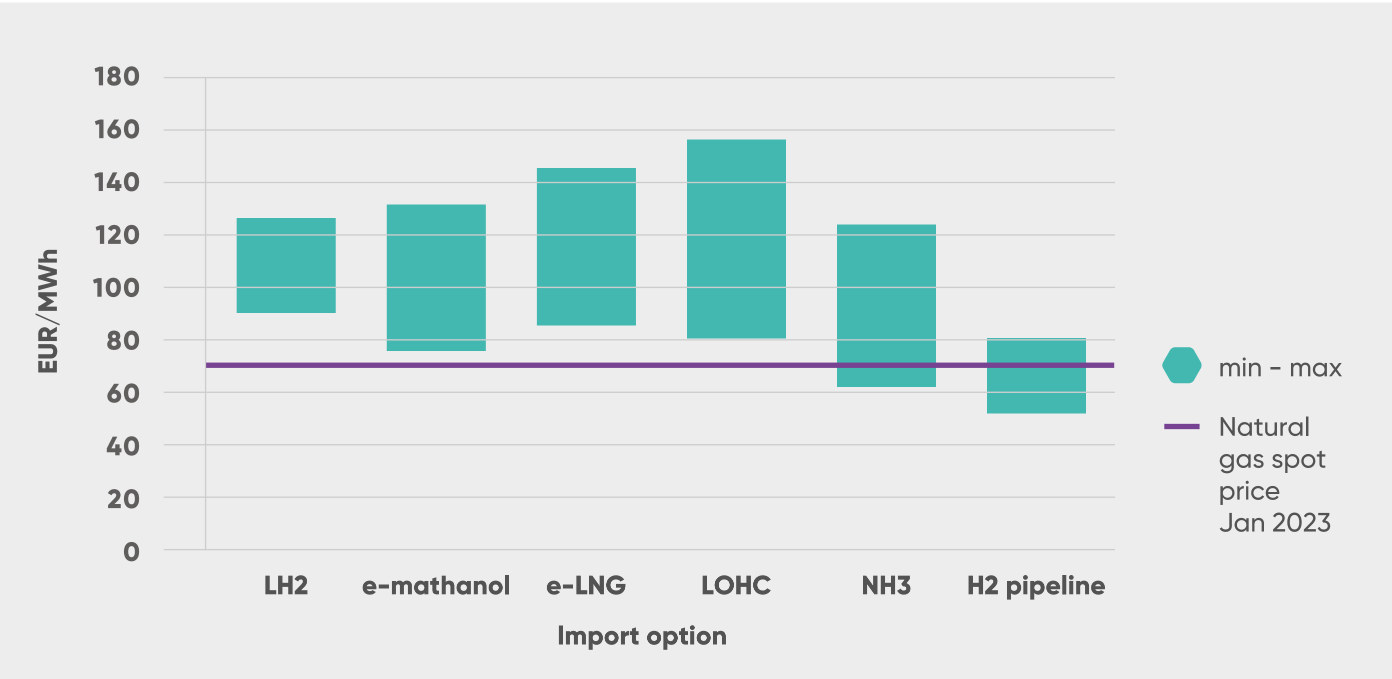


and can be transported as liquids without cooling. LOHCs are very similar to crude oil and oil products, so the existing oil transport infrastructure could be adapted to transport LOHCs – allowing for a cost-effective transportation at a large scale with existing infrastructure. However, a power-intensive dehydrogenation process and the need for the vessels to return with the dehydrogenated carrier can impact the economics. Nevertheless, if a low-cost, waste heat source can be used for dehydrogenation, LOHC can become the lowest cost option (JRC, 2022).

In addition to the above, it is also possible to use e-methanol, e-LNG or even synthetic gasoline as hydrogen carriers, with each of those options being able to leverage existing storage, transportation and shipping infrastructure. Especially in the case of e-LNG, the potential to tap into to the existing natural gas infrastructure, including LNG terminals, around the EU would be very attractive. However, since these molecules all need carbon for the synthesis process, their competitiveness is often conditional on access to an abundant and low-cost source of CO2. As a consequence, those carriers are usually more expensive to produce – especially if direct air capture (DAC) technology is to be used as a source of the CO2. On the other hand, feasibility could be improved through the use of excess CO2 from industrial sites where those synthetic fuels are consumed, often on the same sites as import facilities, potentially opening the possibility for closed-loop circular CO2 utilization.

Compared to the listed options, the use of ammonia as a hydrogen carrier offers some advantages. Ammonia has a higher boiling temperature than hydrogen (-33°C against -253°C), which makes liquefaction and transportation easier

Figure 33: COST OF RENEWABLE ENERGY DELIVERED TO THE EU AS HYDROGEN OR A HYDROGEN DERIVATIVE IN EUR/MWH, COMPARED TO NATURAL GAS PRICES.
Source: HYDROGEN EUROPE BASED ON EXTERNAL STUDIES[28].



28 / Note: The cost range is defined based on results from various studies and countries where the lower range = most optimistic study and lowest cost export country and the higher range = most pessimistic study from highest cost export country. All options other than „H2 pipeline" are based on imports via shipping. Studies included: (1) TYNDP2022 scenarios; (2) Hydrogen Import Coalition final report; (3) ENTEC – The role of renewable hydrogen import and storage to scale up the EU deployment of renewable hydrogen Import options for chemical energy carriers from renewable sources to Germany; (4) De Santis et al., Cost of long-distance energy transmission by different carriers; (5) F. Schorn et al., Methanol as a renewable energy carrier: An assessment of production and transportation costs for selected global locations; (6) C. Hank et al. Energy efficiency and economic assessment of imported energy carriers based on Renewable electricity.

and less energy intensive. It can also be kept liquid at room temperature when at least 8.6 bar of pressure is maintained. In both cases regular carbon steel tanks are sufficient.

In addition, ammonia is already a globally traded commodity with around 20 Mt traded annually, with around 17-18 Mt by ships. As a result, the logistics infrastructure needed for its efficient and safe handling is already largely in place. If ammonia were to become a dominant hydrogen carrier, this infrastructure would have to be expanded significantly, but to some extent, the existing LPG storage and transport infrastructure could also be relatively easily repurposed to handle ammonia as well – due to similar storage requirements. While ammonia is very toxic, protocols for its safe handling are already in place and the safety track record proves that ammonia shipments can be executed in a safe way at a large scale.

As a result, 12 of the above-mentioned 15 large-scale green hydrogen projects, being developed for the purpose of hydrogen exports, have announced that ammonia will be the chosen hydrogen carrier.

One of those is the NEOM project - a giga-size project, scheduled to come online in 2026 in Saudi Arabia. A total of 1.2 million tonnes of green ammonia are planned to be produced annually and sold to Air Products, which will take care of its export to international markets. Ammonia will then be converted back to hydrogen to fuel the hydrogen mobility market. The project, which brings together Air Products, ACWA Power and NEOM, has announced a budget of USD 8.5 billion, planning for the installation of a 4 GW solar and wind generation.

Similarly, the HYPORT Duqm project is planning the installation of a 1.3 GW solar and wind park where hydrogen would be produced from desalinated water and converted into green ammonia in Oman. The green ammonia will then be exported to the target international markets. A sign term sheet was also signed between Yara, ACME and Scatec for the production of a 100 kt/y green ammonia facility in Oman, with potential up-scale to 1.1 Mt/y on a second phase, aiming at exportation to Europe and Asia.

The German government is also working on long-term agreements with many locations where the production of green ammonia is optimal. An agreement has been made with Namibia for the supply of green ammonia starting in 2026 with the potential to reach a 3 GW electrolyser installed capacity. The first batch of ammonia imports already took place earlier this year in Germany – although at a very small volume. A total of 13 tonnes of ammonia were delivered to Hamburg coming from the United Arab Emirates.

There are also numerous initiatives, aimed at scaling up existing ammonia terminals' transfer capacity or creation of new ammonia terminals. Some of the more notable initiatives include Uniper's plans to establish a German national hub for hydrogen in Wilhelmshaven with both local hydrogen production via electrolysis and import of hydrogen via ammonia as well as OCI's plan to significantly expand the existing ammonia import facility at the Port of Rotterdam. The company announced a two-stage plan to increase throughput capacity from 400,000 tons per year currently to 1.2 million tons per year by the end of 2023 and more than three million tons per year in the next phase. The port of Antwerp-Bruges is also planning construction of an open-access ammonia import terminal that could be operational in 2027. Air Products and Mabanaft have also announced plans to build a green energy import terminal in Hamburg based on ammonia as the energy carrier.

So, while we will most likely see other options gain more prominence once the regulatory framework is clear and settled and it is certainly premature to declare ammonia as the winner – it is clearly a frontrunner at this early stage.

6.1.1. Certification of clean ammonia

If ammonia (or any other hydrogen carrier), is to fulfil its potential role, a clear and trustworthy ammonia certification scheme is necessary – both for compliance with regulatory requirements and targets as well as for reliable disclosure of characteristics (origin, GHG footprint) of the energy/product to the end consumer (e.g. for CSR purposes). Some of the recent regulatory developments creating the need for certification of ammonia for compliance purposes include the RED II revision, the EU Taxonomy on sustainable finance, FuelEU Maritime, the EU ETS extension to the maritime sector and CBAM. The hydrogen and decarbonised gas market package will also define the low-carbon hydrogen/ammonia with its own methodology for carbon footprint calculation.

Regardless of the purpose (voluntary disclosure and/or compliance), certification requires the definition of many elements (data to be collected, compliance criteria, methodologies, means of verification, …). The development of such a certification scheme is not helped by the fact that the final EU framework regulating hydrogen production and use is not set yet, nor by the fact that the existing (or proposed) regulations are not always aligned when it comes to definitions and scope of GHG emissions which should be included in the final carbon footprint – e.g., RED II, the EU taxonomy and FuelEU Maritime require the consideration of cradle to grave emissions (excl. emissions from the construction of assets), while the EU ETS and by extension also CBAM considers only direct GHG emissions from the production process.

Consequently, **at this moment it's challenging to provide evidence that green/blue ammonia is compliant with European rules because the official accredited certificates or voluntary certification schemes are not existing yet.** The development of these schemes must be accelerated in order to create trust in product labelling. Certification is essential for differentiating renewable and low-carbon ammonia from unabated fossil ammonia – and equally so for imports as well as for domestic production.

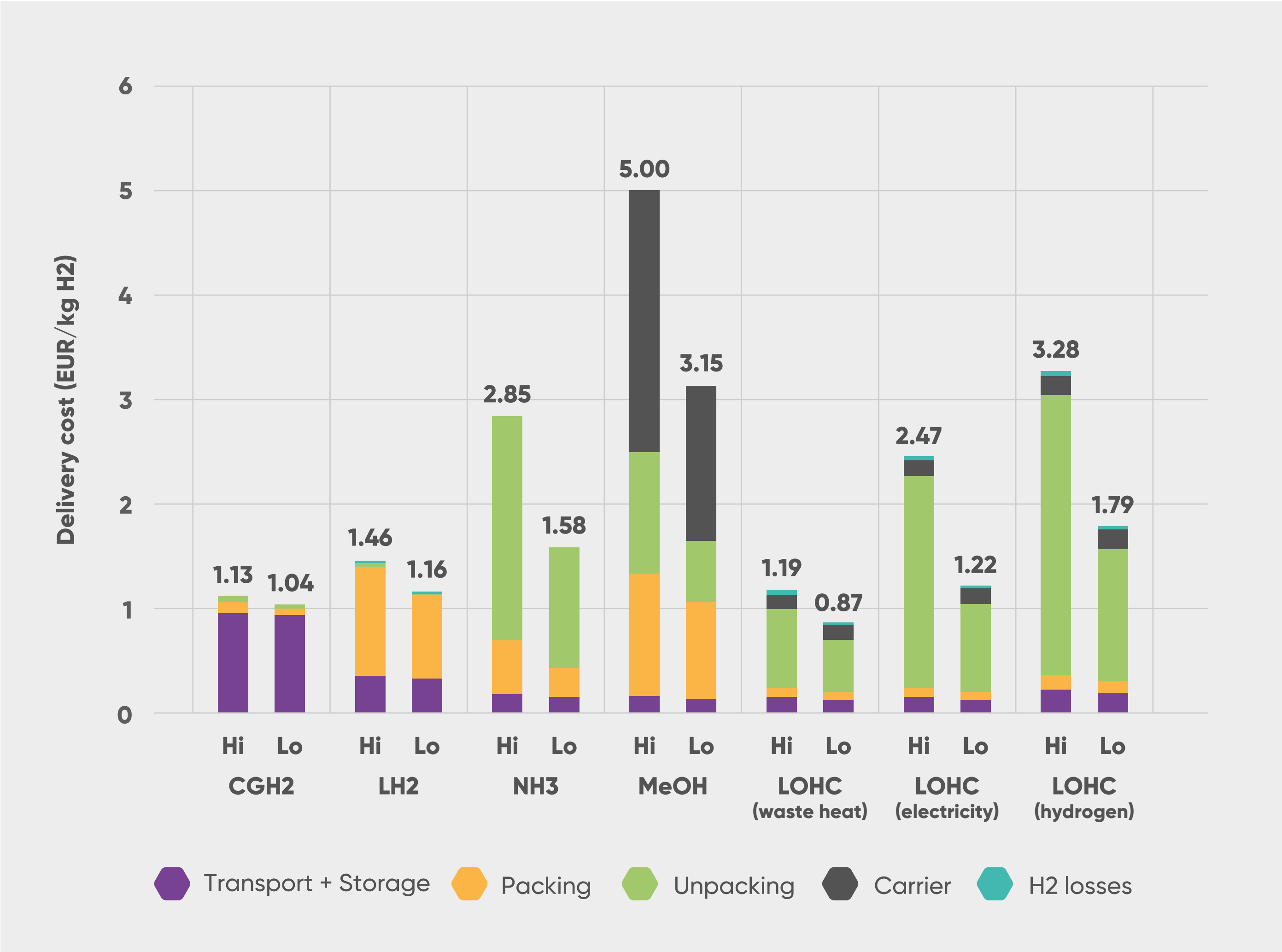
6.1.2. Cracking of ammonia

Another potential barrier to the wide use of ammonia as a hydrogen carrier is related to the costs of conversion of ammonia back to hydrogen. Ammonia cracking is an endothermic process and can be regarded as the reverse of the synthesis reaction. In order to achieve high conversion rates (>99%), ammonia cracking has to operate at temperatures higher than 400°C. Conversion equilibria decrease by increasing pressure and kinetic limitations require high temperatures to achieve a significant hydrogen yield (JRC, 2022). While there are some promising emerging technologies, including feedstock versatile membrane reactors[29], the only technology available at an industrial scale now would be thermal reforming, requiring around 52 GJ/tH2 with a conversion of 98.5% (JRC, 2022). A lot of R&D is still needed for ammonia crackers to reach the market, but companies such as Ballard Power Systems and Amogy have already announced the demonstration of an ammonia-to-power platform in 2023[30].

Given the high energy intensity of the dehydrogenation process, using fossil fuels like natural gas as the heating source would increase the overall carbon footprint of hydrogen above the maximum 28.2 gCO2/MJ required by the Renewable Energy Directive. Therefore, unless a relatively low-cost renewable or waste heat source is available, the hydrogen itself would have to be used to provide the necessary energy. Either way, the costs of ammonia cracking can form, by far, the largest portion of hydrogen delivery costs (excluding costs of hydrogen itself) - drastically impacting the cost competitiveness of imported hydrogen.

29 / More information at: https://www.h2site.eu/en/
30 / More information at: https://www.ballard.com/about-ballard/newsroom/news-releases/2022/12/08/amogy-and-ballard-sign-contract-to-integrate-maritime-fuel-cell-engines-in-zero-emission-ammonia-to-power-platform

Figure 34: HYDROGEN DELIVERY COSTS BY SHIP. HIGH AND LOW ELECTRICITY PRICES FOR EACH CARRIER.
Source: (JRC, 2022)[31].



Therefore avoiding the dehydrogenation costs altogether, by direct use of ammonia as a fuel or as a feedstock – could, in many cases be the key condition for ensuring the financial viability of importing renewable energy in the form of ammonia.

31 / CGH2 – compressed hydrogen; LH2 – liquefied hydrogen; NH3 – ammonia, MeOH – methanol, LOHC – liquid organic hydrogen carrier.

6.2. Energy storage and power generation

To replace fossil fuels use the EU will have to engage in a massive increase in renewable power generation as well as deep electrification of various energy end-use sectors.

Most projections foresee an almost complete decarbonization of power generation by 2050. While nuclear energy and biomass-based power generation will play their role, due to the decrease in costs of wind and solar technologies it is expected that the latter two will constitute most of the total electricity generation in the EU. In some countries such as Portugal or Denmark, the share of these technologies in power generation could grow to reach almost 100%. This will naturally be accompanied by a gradual phasing out of the existing dispatchable (fossil-fuel-based) power generation sources. Combined with the fact that the concentration of renewable energy potential in the EU is not well correlated with areas of electricity demand, this will potentially result in high renewable energy curtailment. For example, already in 2019 wind onshore electricity generation in the North was significantly higher than in the South of Germany, and about 5,100 GWh had to be curtailed.

Simultaneously to the growth of the share of variable renewable technologies in the power supply side, electrification rates will also have to increase. The European Commission's forecasts show that electricity will directly cover 57% of final energy uses.

Together, these two trends – increasing power generation from variable renewables and increasing electrification of energy end-use will create a serious challenge to the stability of the power system. The variable profile of renewable power generation above a certain threshold in combination with seasonality and variability of demand requires both short-term balancing as well as balancing over weeks and entire seasons. These mechanisms need to stabilize the grid, absorb excessive power generation (e.g., in summer) and provide power in periods of low renewable production when energy demand is high (e.g., in winter) (FCH 2 JU, 2019).

Batteries can provide a highly efficient method for storing energy for short periods. They are, however, expensive relative to the amount of energy stored and have low energy density. This implies that they are ill-suited for storing large amounts of energy and for storing energy over long periods. Pumped hydro storage is an option for long-term energy storage. Its capacity in the EU is limited, however – while the technical potential is estimated between 30 and 80 TWh, there are additional natural, regulatory, and societal restrictions. Furthermore, these capacities are not readily available across Europe, but only in selected areas. (FCH 2 JU, 2019)

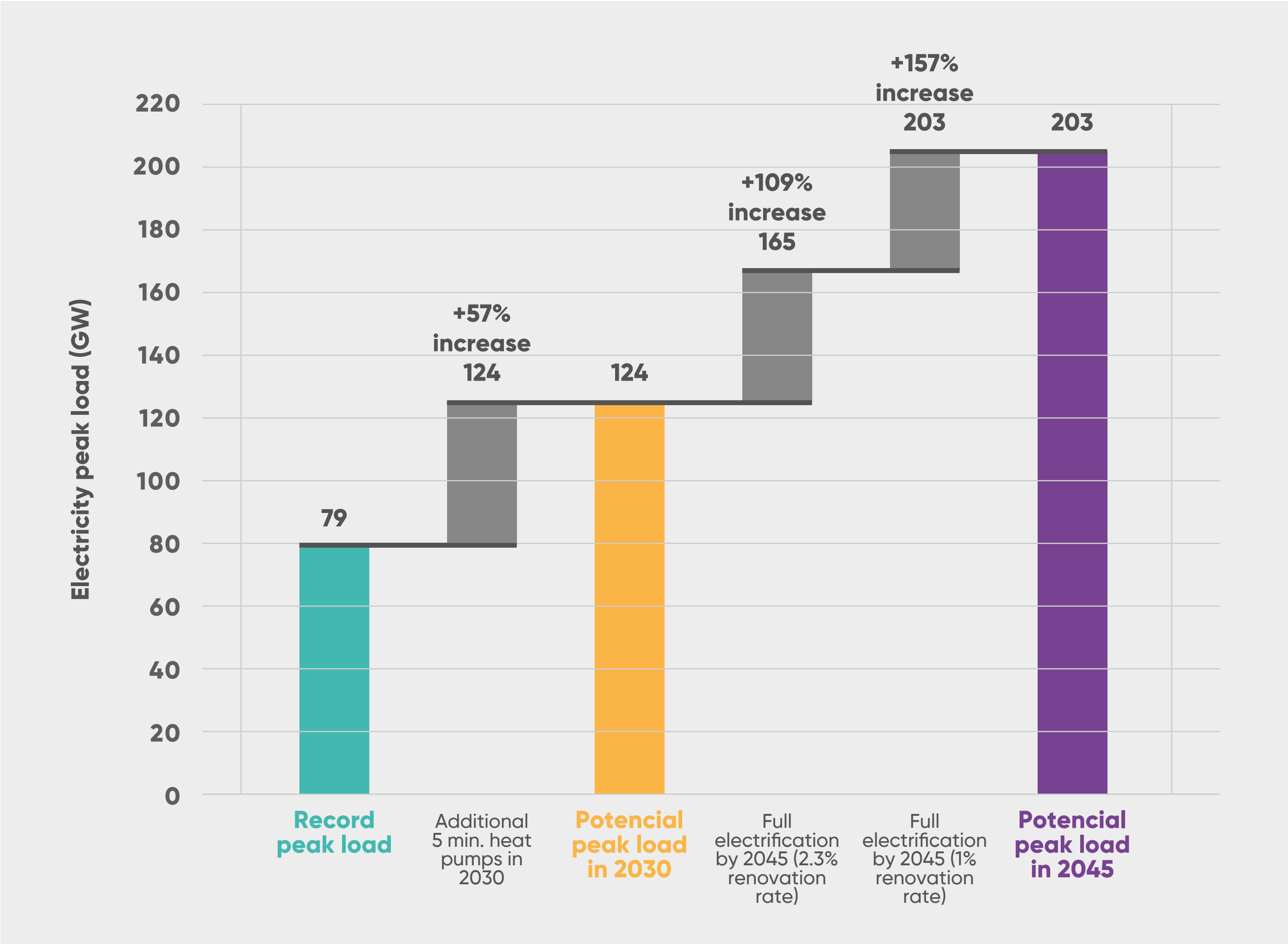
Especially the electrification of heating will create a significant challenge that could not be met with the use of existing energy storage solutions or demand-side-response (DSR) type measures. Even assuming the high energy efficiency of heat pumps, the high seasonality of energy demand for heating, coupled with a decrease in heat pump efficiency in low temperatures, will result in a significant increase in peak load power demand. In the example of Germany, even if buildings' renovation rate reaches 2.3%, ensuring buildings are more energy efficient, the power grid and power generation capabilities would have to handle an increase of 109% in peak load to fully electrify the heating sector by 2045. If the renovation rate remains at current levels of around 1%, the peak load would increase by as much as 157%. (Frontier Economics, 2021).

In the EU-27, if 91 million additional heat pumps are installed by 2050, the grid would have to handle a peak load of 292 GW only from heat pumps. This represents about 65% of the total average peak load of the EU-27 in 2018.[32]

The seasonal energy supply and demand variability are where hydrogen offers a unique solution, indispensable to decarbonise the power generation and heating sectors reliably and independently from weather or seasonal conditions. In its quality as a dispatchable energy carrier, it can easily cope with high peak demands and is available any time during the year and day to support grid balancing actions based on hydrogen storage/use strategies in local and regional networks. It is also complementary to, and

32 / Based in data retrieved from (Guidehouse, 2022) and (ENTSO-E and ENTSO-G, 2022).

Figure 35: ELECTRICITY PEAK LOAD ADDITIONS AND CUMULATIVE PEAK LOAD IN 2030 AND 2045 FOR DIFFERENT SCENARIOS OF ELECTRIFICATION OF THE HEATING SECTOR IN GERMANY.
Source: (FRONTIER ECONOMICS, 2021).



offers a diversification option, from the direct electrification of the heating sector. Energy conversion in combined heat and power generators not only covers the thermal needs whenever required but also reduces the load on the electrical side when demand is usually highest, avoiding grid congestion at the distribution level and allowing to optimise overall costs of the energy system (Clean Hydrogen JU, 2021).

Large-scale seasonal energy storage can be achieved by storing hydrogen in underground salt caverns and gas fields, which are located in many places in Europe. Some of the salt caverns, which are used to store natural gas today, could be repurposed to store hydrogen.

However, as underground storage sites are not uniformly available throughout Europe, also other hydrogen-based molecules - including ammonia - can be used to serve the needs of the power sector of the future.

A single ammonia tank with a capacity of 50,000 tonnes would provide an energy storage potential of close to 260 GWh, which is comparable to the energy storage potential of a 750,000 m3 salt cavern dedicated to hydrogen storage.

For reference, the world's largest battery energy storage system (BESS) in Moss Landing, US has an energy storage capacity of 1.6 GWh – i.e. more than 160 times less than a single large-scale ammonia tank.

There are multiple ways of turning ammonia back into electricity - from using a traditional approach and burning it in a combustion engine or a turbine to electrochemical reactions in fuel cells.

Fuel cells offer a unique proposition, relative to other technologies, in that they offer the potential to silently generate clean energy at high electrical efficiency and with zero emissions. This positions fuel cells as a key technology to decarbonise a number of end-user demands across a large range of sizes. Because of fast response times and low maintenance needs, fuel cells are an ideal component of back-up and temporary (portable) power systems. Fuel cells can also be used as main power sources for off-grid locations. High temperature fuel cells can also be used for Combined Heat and Power (CHP) applications – providing heat for buildings (directly or via district heating networks) as well as electricity at high efficiency (Clean Hydrogen JU, 2021).

However, the use of fuel cells with ammonia comes with several challenges. In the case of the most common PEM fuel cells (as well as other low-temperature fuel cell technologies), due to the low operating temperature, the thermodynamic decomposition of ammonia requires the use of an external cracking reactor to convert ammonia into hydrogen first, reducing energy efficiency and generating additional costs. In addition to that, ammonia is lethal to most membranes utilised in PEM fuel cells – requiring careful purification of the hydrogen feed.

Use of ammonia with alkaline fuel cells (AFC) or solid oxide fuel cells (SOFC) are also interesting solutions, coming with their own trade-offs. In the case of Alkaline fuel cells, the required land footprint for multi-MW solutions would be a challenge, making it more suitable for small-scale back-up and temporary (portable) power systems. In the case of SOFCs, the main advantage is that, at high temperatures, ammonia can be directly decomposed into hydrogen – eliminating the need for an external cracking reactor. The slow start-up and load ramp-up and downtimes make them less suitable for flexible power generation but rather for CHP applications with a relatively steady load.

Therefore, when ammonia would be used as a fuel, gas turbines (GTs) seem to be the preferred solution – especially at the hundreds of MW-range. GTs provide dispatchable power (and heat) following the system and market requirements. In a system with an increasing share of variable electricity production from non-dispatchable renewable energy sources, the high flexibility of gas turbine-based power plants can effectively ensure the grid stability and security of supply. Used also in cogeneration systems, together with thermal storage, they can flexibly provide the necessary amounts of power and heat for industrial settings or district heating. Their main advantage lies however in the power density, which enables large amounts of power to be available within a very short time and with a small footprint. Moreover, GTs have significant fuel flexibility, being able to burn a large variety of different fuels and with varying fuel composition (Clean Hydrogen JU, 2021).

In combined cycle (CCGT) configurations, GTs can reach thermal efficiencies up to ~63%, matching the electrical efficiency of fuel cells.

The challenge of using ammonia as a fuel in GTs comes from its unfavourable combustion properties related to low flammability, as well as a low flame speed and radiation heat transfer. Adding to the poor combustion properties of ammonia, complete GHG emissions avoidance might also not be achieved due to NOx and potentially also N2O emissions. Both can be managed with the use of certain catalysts and the use of Exhaust Gas Treatment Systems. Blending ammonia with hydrogen in the fuel mix can also partially provide a solution.

The use of ammonia for power generation seems particularly attractive in isolated locations with poor access to cheap renewable sources and, like islands such as Japan, where the import of green molecules is one of the main strategies for decarbonisation of the grid. Japan is targeting to grow its demand for ammonia as fuel to 3 million tonnes a year by 2030. The biggest power generator, JERA, has already acted on this pledge and is aiming at the use of 20% of ammonia in its fuel mix by 2035, with the goal of also developing technology to use 100% ammonia in 2040. The company has signed an MoU with Yara Clean Ammonia as the potential partner for a long-term supply contract starting in 2027 of 500 kt of NH3 a year, enough to achieve a 20% rate co-firing at one of the two biggest units at the Hekinan plant.

In parallel, Mitsubishi Heavy Industries is also highly invested in ammonia power generation technology. It is currently developing a 40 MW gas turbine combined cycle that can directly burn a 100% ammonia input and is foreseeing to have it commercially ready by 2025. The company has also recently signed an MoU with Japanese power generator JERA to jointly explore developing a 60-MW CCGT plant fueled with 100% ammonia on Singapore's Jurong Island. Similar agreements have been reached with Indonesia's Institut Teknologi Bandung (ITB). The company is also developing ammonia co-firing solutions, having recently signed an MoU with a power company in Chile (Guacolda Energia SpA) to begin the study for the introduction of 30% ammonia co-firing at a 758 MW coal power plant.

Outside of technology challenges, the costs of power generation with decarbonised ammonia as a fuel will also remain a challenge in the immediate future. While ammonia gas turbines can achieve the same electrical efficiency as conventional gas turbines do, due to ammonia's lower heating value and combustion properties, CAPEX for a 100% ammonia gas turbine can be expected to be at least 1.5 times higher than for a conventional gas turbine – at least at the initial stage of the technology development.

Combined with high decarbonised ammonia fuel costs, this will make it difficult to find a business case for baseload power generation with ammonia as a fuel. However, if this solution is to compete with other flexible and dispatchable power sources, used primarily to provide peak power, the business case is relatively promising. Using natural gas-fired CCGT with CCS as a comparative solution and assuming a 25% capacity factor[33], the ammonia CCGT can become cost competitive with a natural gas solution even at relatively low assumed natural gas prices. With the expected medium-term equilibrium natural gas price (as expected by the IEA in 2025) of 50 EUR/MWh, the break-even point for ammonia-fired CCGT is reached at the ammonia fuel price of around 449 EUR/t, which corresponds to hydrogen delivery costs of 1.6 EUR/kg. While still challenging today, given the expected reduction of low carbon ammonia production costs, achieving a positive business case is certainly possible.

According to the IEA, globally, the use of ammonia for power generation is expected to reach 60 Mt per year in the Sustainable Development Scenario and 85 Mt in the Net Zero Emissions scenario (IEA, 2021).

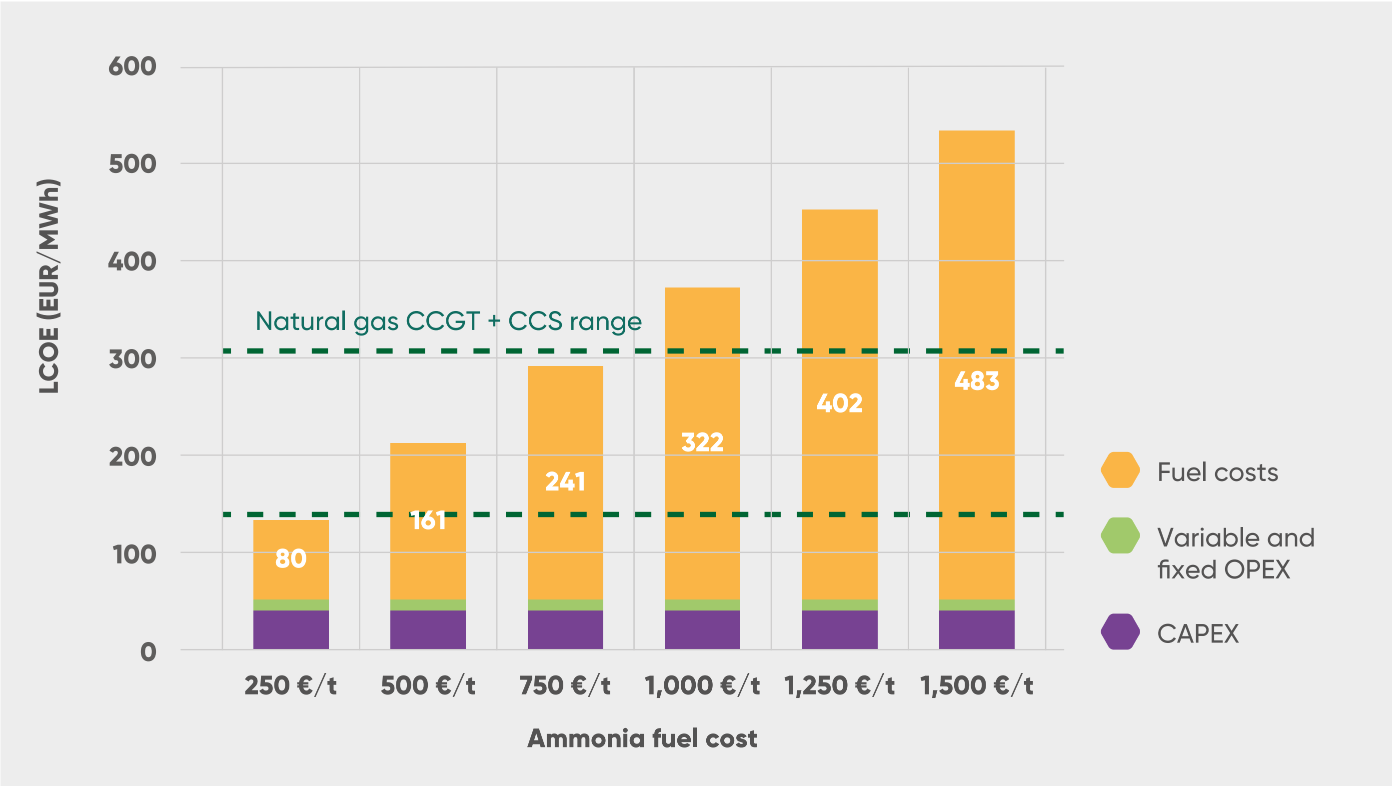
6.3. Ammonia in mobility – the maritime sector

Another potentially key sector for future new demand for decarbonised ammonia applications is the international shipping sector.

Maritime shipping is an integral part of the global freight transportation system. Depending on the type of route, ships compete with other modes of transport such as railways and aircraft. For many occasions, however, shipping is the

33 / Identified in (BNEF, 2019) as approximate capacity factor for technology of this type, required in a 2°C decarbonization scenario.

Figure 36: LCOE (IN EUR/MWH) FOR AMMONIA-FIRED CCGT DEPENDING ON AMMONIA FUEL COSTS.
Source: HYDROGEN EUROPE.



Note: Natural gas CCGT + CCS range estimated for a natural gas cost range between 20 EUR/MWh and 110 EUR/MWh.

only option to transport the goods from one point to their destination.

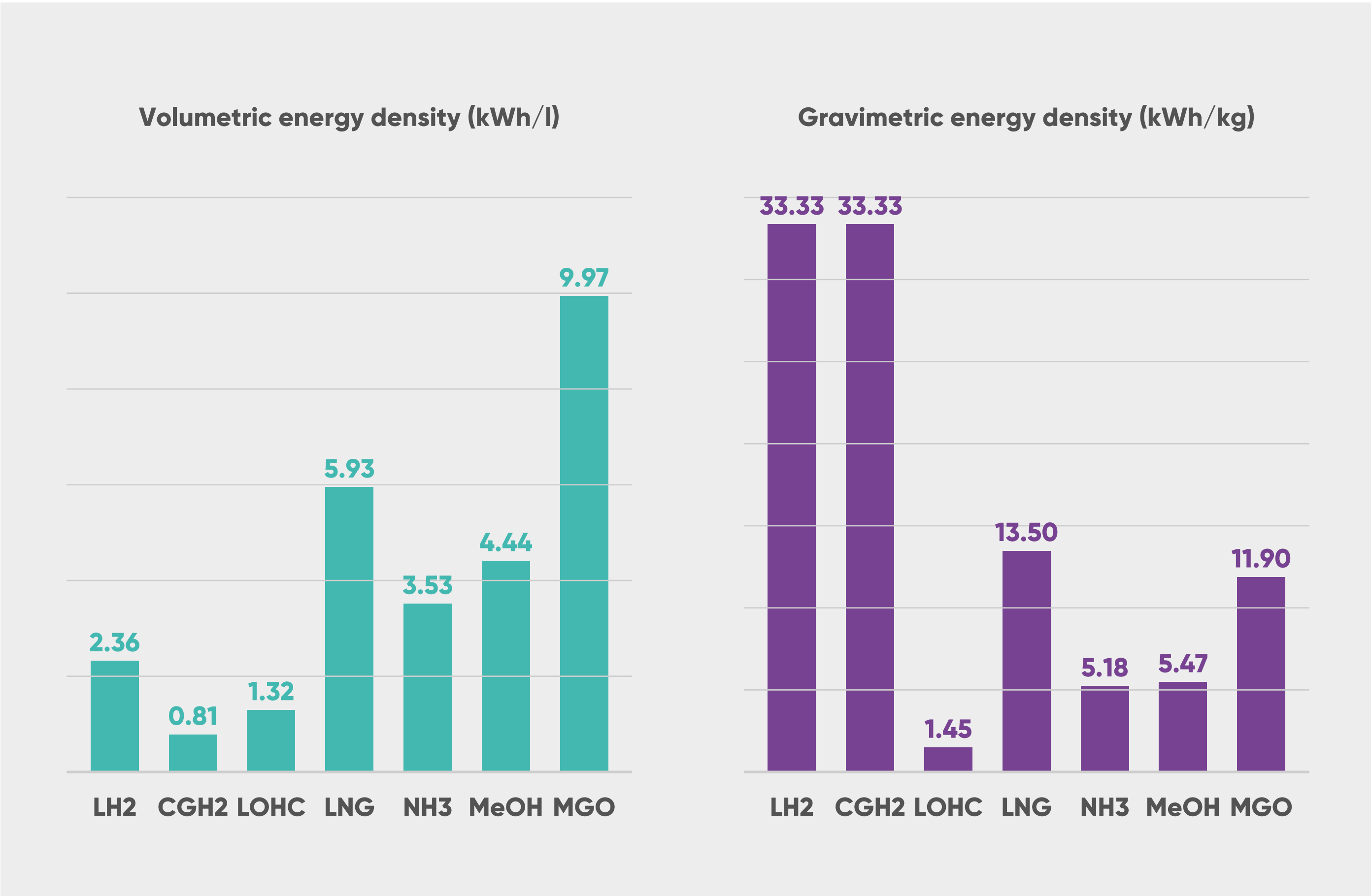
The maritime sector currently uses predominantly petroleum-based heavy fuel oil as a fuel. The fourth International Maritime Organisation GHG study[34] estimates that the shipping industry was responsible for the emission of 1,078 million tonnes of CO2e, including CO2, CH4 and N2O emissions. Apart from greenhouse gases, ships are also a significant source of air pollutants emissions – including NOx and others. The same study estimates that international shipping emitted approximately 17.1 million tonnes of NOx emissions and 9.6 million tonnes of SOx in 2018. At high concentrations, gaseous SOx can harm trees and plants by damaging foliage and decreasing growth. This gas is also a contributor towards acid rain. Stringent legislation is already in place to minimize NOx and SOx emissions from the maritime sector, but the pressure towards the reduction of GHG has been significantly slower.

Different alternative fuels/propulsion systems can be considered for shipping, with different advantages and disadvantages and different levels of decarbonisation potential. Energy density, among other properties, in an important aspect to factor in when choosing the right sustainable option for shipping. The energy density of different fuels can be seen in Figure 36.

Direct electrification offers the highest energy conversion efficiency, as well as zero TTW emissions. However, due to low energy density of battery-electric storage systems, it is not a suitable solution for the maritime sector – outside of only relatively small vessels which can recharge often or operate in the port area.

34 / Fourth Greenhouse Gas Study 2020, https://www.imo.org/en/OurWork/Environment/Pages/Fourth-IMO-Greenhouse-Gas-Study-2020.aspx

Figure 37: THE ENERGY DENSITY OF SELECTED FUELS.
Source: HYDROGEN EUROPE.



On the other hand, biofuels have significant advantages regarding high energy density and the possibility to be used as drop-in fuels, allowing them to take advantage of existing bunkering infrastructure and decarbonise the existing fleet of vessels. The challenge, in this case, is the limited availability of both sustainable first-generation biofuels and advanced biofuels, making it difficult for this solution to fully guarantee the decarbonisation of the sector.

Therefore, there is a growing consensus that hydrogen and hydrogen-based e-fuels, including ammonia, will play a major role in the decarbonisation of shipping.

The use of ammonia as a shipping fuel is, however, by far, not the only solution to decarbonise the sector, with other possibilities including the use of hydrogen directly as a fuel, using LOHC as a hydrogen carrier or use of other hydrogen-based e-fuels like methanol.

Direct use of hydrogen – either in compressed or liquefied form – has some advantages. One of them is the fact that it requires a less complicated fuel production process, as only one additional step is needed after hydrogen production (compression or liquefaction, respectively). Usually, this translates into lower costs of production compared to the alternatives. But, even in its liquid form, hydrogen has a relatively lower energy density compared to synthetic fuels. In the short term, direct use seems better suited to inland, coastal, and short-sea shipping. In the medium to long run, thanks to larger fuel cell systems, new vessel designs and better storage technologies, medium distance shipping could also be tackled with hydrogen. Its feasibility for deep-sea shipping applications, especially at the current level of technology development, is thus limited. Liquid hydrogen also needs, after production, to be transported and dispensed at the point of use, which can be more technically complex than the use of synthetic fuels.

Methanol and other e-fuels have higher energy density – even compared to ammonia - and are generally simpler to handle. In this case, however, the final cost of the fuels, and thus their financial feasibility, is heavily dependent on the costs of CO2 supply – which is needed in the fuel synthesis process. By far the cheapest source of CO2 would be to use the CO2 point captured from industrial processes or power plants, yet the long-term sustainability of this pathway is questionable. The CO2 saving credit can go either to the industry, which has captured it or to the end-user (in this case a ship), it can never go to both. If it is the industry that gets the CO2 saving credits, the synthetic fuel will just be releasing GHG to the atmosphere like its fossil fuel equivalent. If, however, the CO2 credit is attached to the e-fuel, then, while the fuel itself is climate neutral, the long-term availability of CO2 is uncertain. If the ultimate goal of the EU is to become a fully decarbonized economy, the industry would have to be decarbonized as well, meaning that, at some point, either the captured CO2 would have to be destined for permanent storage or the industry will transition to another zero-emission solution - either way, limiting the availability of CO2 for CCU. Furthermore, the use of CO2 from fossil sources might also potentially lead to a lock-in effect.

For this reason, the EU policymakers seem intent on limiting the possibility of using CO2 captured from activities covered by the EU ETS only before 2041 or even 2036 for CO2 stemming from the combustion of fuels for electricity generation[35]. Alternative sources of CO2, which include:

- the CO2 has been captured from the air,
- the captured CO2 from the production or the combustion of biofuels, bioliquids or biomass fuels,
- the captured CO2 from the combustion of RFNBOs or recycled carbon fuels,
- the captured CO2 from a geological source of CO2 and the CO2 was previously released naturally, are either limited in supply or relatively expensive.

In this context ammonia as a maritime fuel offers a good balance between good energy density and relatively low fuel production costs – not influenced by CO2 supply costs.

Yet, just looking at energy densities of various fuels does not give the complete picture.

For example, compressed hydrogen is usually stored in cylindrical containers, with relatively thick walls, required to withstand the high pressure, adding around 20% to the fuel volume. If one would consider storing compressed hydrogen in 40-foot containers, then the space lost in between multiple containers as well as the container frame itself would add further space requirements.

In the case of cryogenic fuels like LH2 or LNG, the tanks generally have a double hull design, with a vacuum between the inner and outer container. Besides that, the tanks are rarely filled-up completely in order to leave space for the boil-off gas.

LOHC comes with its own, unique challenges. It can be stored in standard marine fuel tanks but the "spent" carrier, once the hydrogen has been extracted, needs to be also stored onboard. In case of metal hydrides depending on the reaction needed to extract hydrogen, the spent carrier can require even more space than the "loaded" one (e.g. sodium borohydride). Furthermore, as hydrogen needs to be extracted before it can be used, additional dehydrogenation equipment and hydrogen purification equipment needs to be accommodated as well. Similarly, to be able to use PEM

35 / Based on the proposed EU Commissions delegated act on on establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels from December 2022.

FC in combination with any of the e-fuels, additional fuel reforming/cracking equipment would have to be included in the powertrain setup, increasing the overall space requirements of the system.

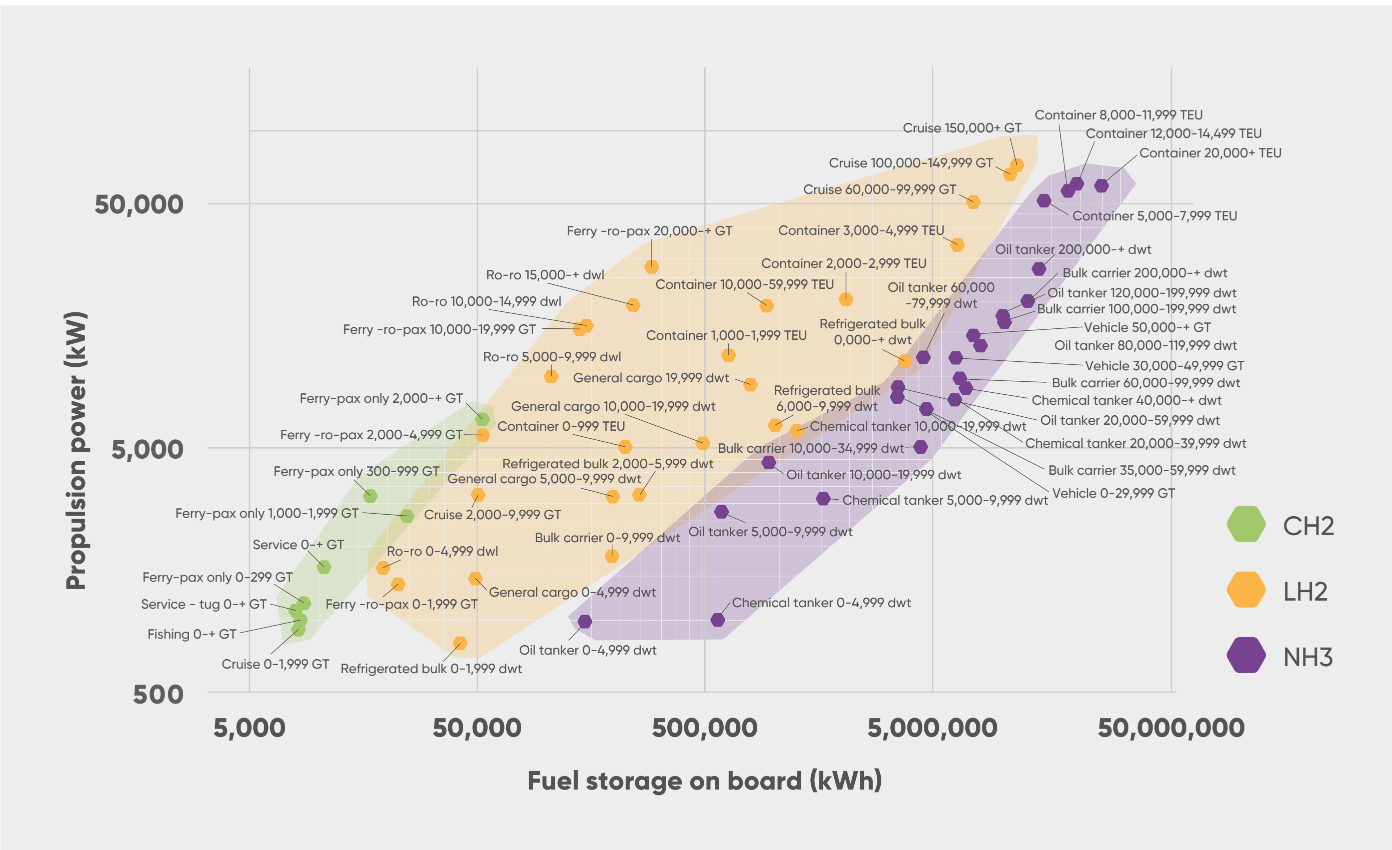
All things considered, the exact impact of using alternative fuels on commercial space available on any given ship would need careful examination on a case-by-case basis. It is nevertheless clear that for all options a switch to alternative fuels will require more space dedicated to the fuel and energy systems that were the case with standard marine fuel oils. This will not only translate into costs of storage tanks and extra equipment but will also impact on the ship's capacity to carry passengers and/or cargo.

The severity of the impact will of course vary and will depend not only on the chosen technology but will also greatly depend on the ship's operational profile. It will be most felt in deep-sea shipping applications, where ships need to be able to travel thousands of nautical miles or for ships engaged in tramp trade, without a fixed schedule, requiring additional fuel autonomy to ensure high operational flexibility, which is key for their business model. On the other hand, when ships operate on fixed and relatively short routes, then - even for quite large vessels, like ro-pax ferries – it's possible to use even compressed hydrogen as a solution.

Finally, other considerations, like ease of handling and toxicity of the fuels – will also play a role.

An in-depth cost of ownership analysis was carried out in Hydrogen Europe's "Techno-economic assessment of low-carbon hydrogen technologies for the decarbonisation of shipping" to assess which hydrogen derivative comes out as the most cost-efficient (Hydrogen Europe, 2020). The analysis, which has been carried out for most than 60 different ship types has shown that, for relatively small vessels or an operational profile which allows for frequent refuelling, either compressed or liquified hydrogen will be the preferred option. However for deep-sea shipping

Figure 38: OPTIMUM ZERO-EMISSION OPTION FOR VARIOUS SHIP TYPES.
Source: HYDROGEN EUROPE, 2020.



applications, requiring higher autonomy, synthetic fuels would be the preferred option.

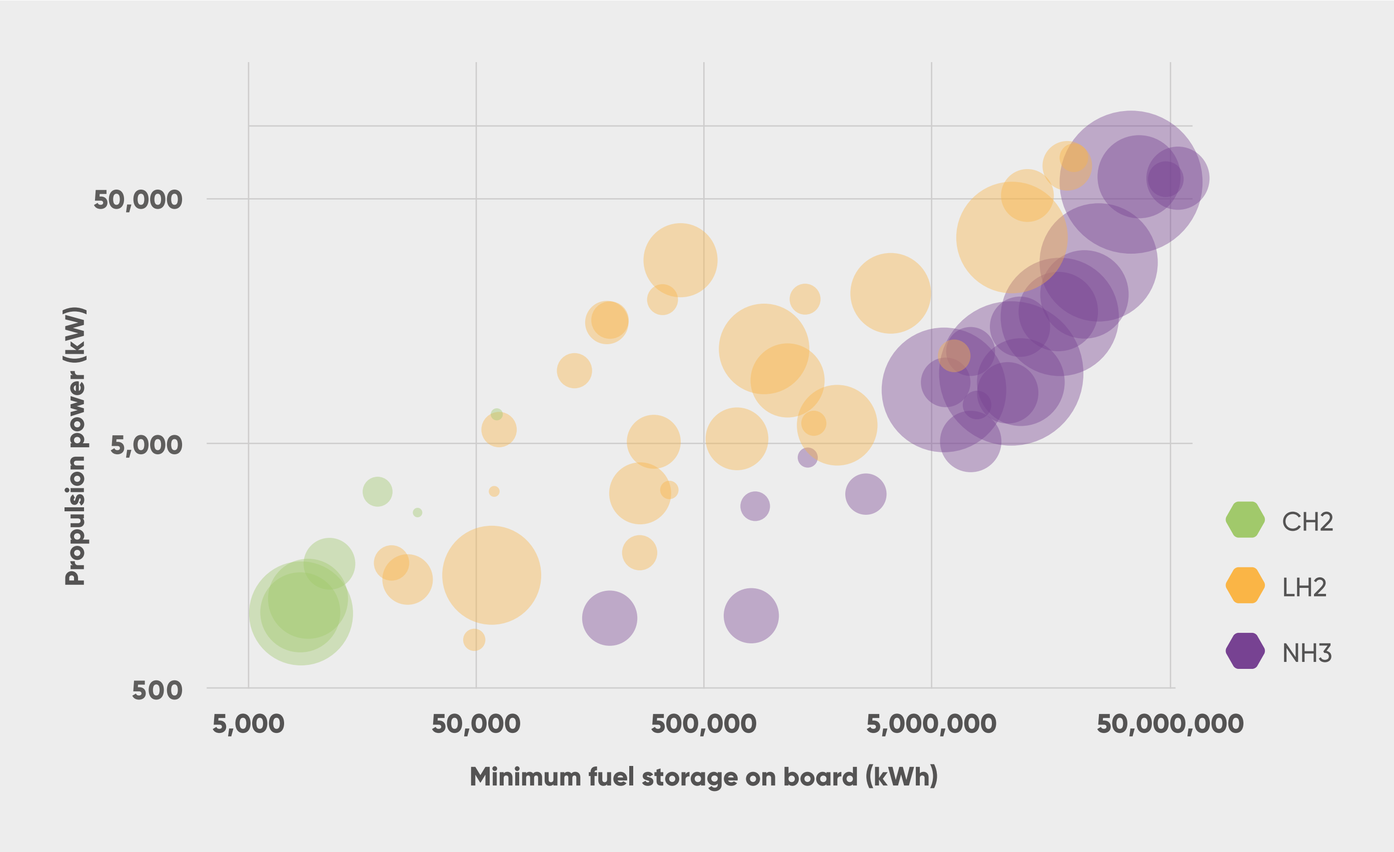
If direct air capture is assumed as the source of CO2, then ammonia offers the best combination of energy density and fuel costs.

Translating those results into market shares of respective options, considering the number of different ship types and their average fuel consumption, ammonia would account for more than 90% of hydrogen-based fuels consumption with LH2 share at below 10% and compressed hydrogen at 0.1%. In terms of number of ships compressed or liquefied hydrogen could potentially be used on more than 77 thousand ships globally, with the deep-sea fleet, for which synthetic fuels like ammonia seem to be the optimal choice is around 21 thousand.

It should be noted however that the comparable cost advantage of ammonia very much depends on the cost of CO2 available for alternative options like e-methanol or e-LNG. With low-cost CO2 those two options would reach cost parity with ammonia for deep sea shipping. Due to described potential regulations limiting the possibility to use point captured CO2 from ETS sectors only until 2041, the above cost analysis assumed CO2 obtained via Direct Air Capture (DAC) technology. Not requiring any carbon for synthesis, gives ammonia an important cost advantage.

According to the IEA, in the Sustainable Development Scenario and Net Zero Emissions by 2050 Scenario, ammonia-fuelled maritime vessels will start to be adopted in the mid-2020s. Container shipping will be the first sector to see ammonia-powered vessels enter the fleet because the routes these ships operate on are fairly consolidated and

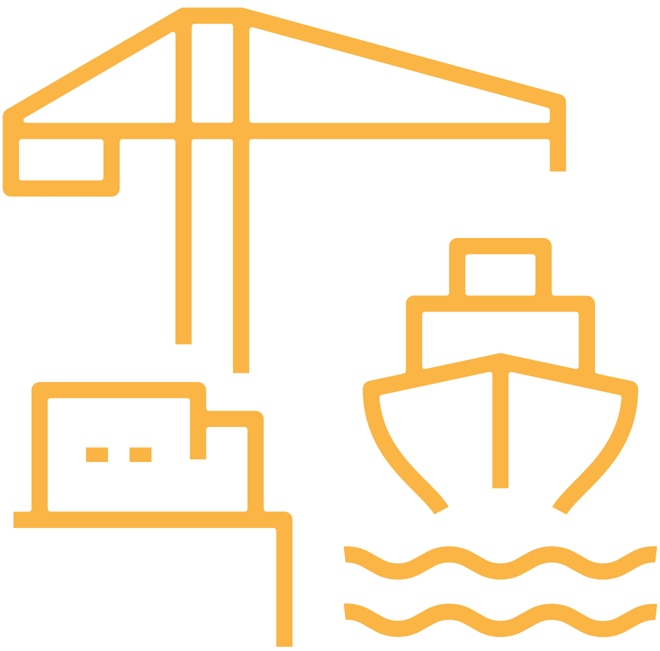
Figure 39: OPTIMUM ZERO-EMISSION OPTION FOR VARIOUS SHIP TYPES AND THEIR RELATIVE TOTAL ENERGY DEMAND (SIZE OF THE BUBBLE).
Source: HYDROGEN EUROPE, 2020.

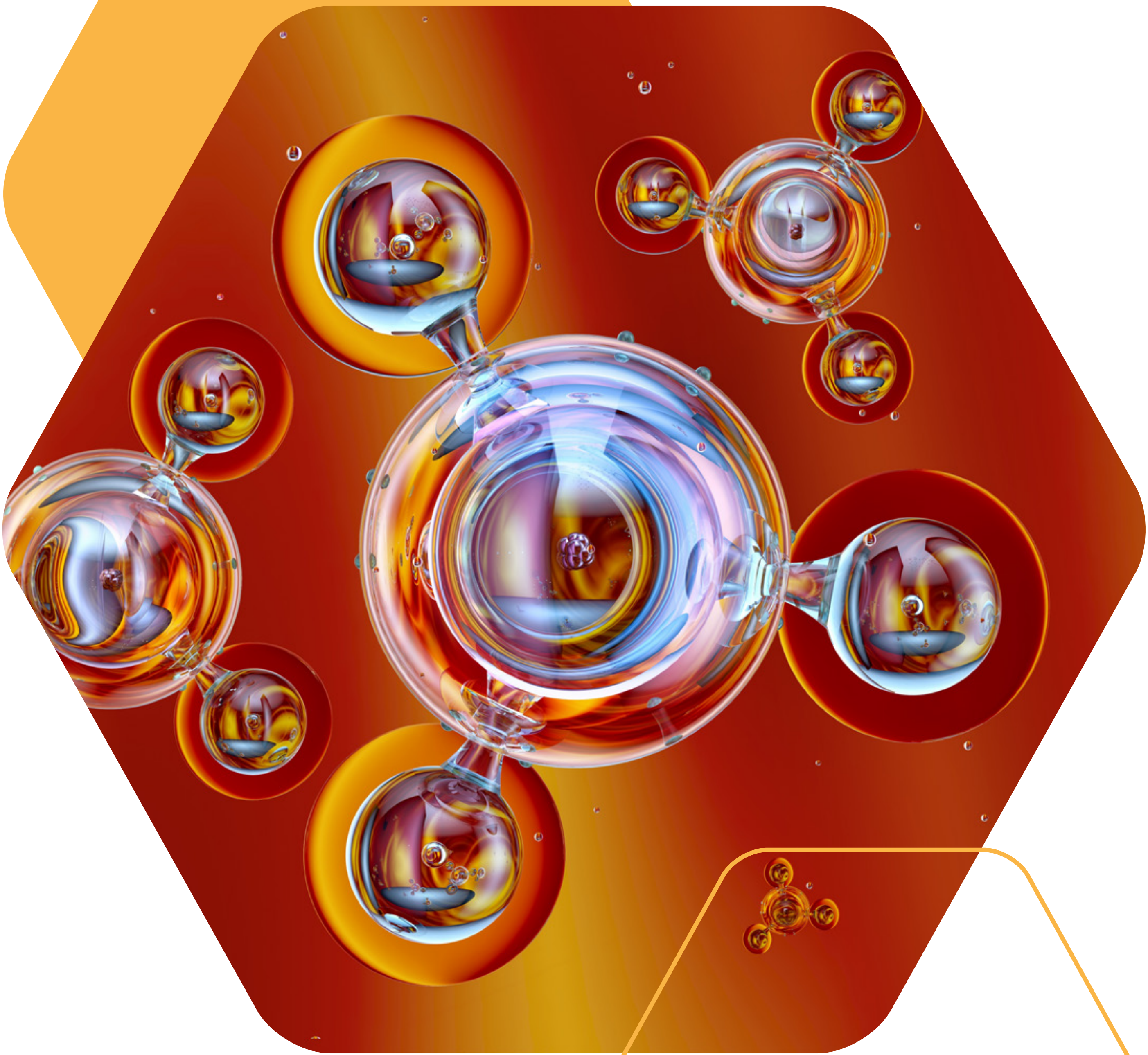


the additional cost can be spread across many customers. Other early movers are expected to be tankers carrying energy commodities that already have the storage capacity and operational experience of handling fuels. In the longer term, ammonia is considered to be the "destination fuel" for ocean-going vessels in these scenarios, accounting for around one-quarter of total final consumption in national and international maritime shipping in 2050 in the Sustainable Development Scenario, and around 45% in the Net Zero Emissions by 2050 Scenario. By then, the total tonnage of ammonia used as a shipping fuel will be equivalent to more than half the volume used for conventional agricultural and industrial uses in the Sustainable Development Scenario and 110% in the Net Zero Emissions by 2050 Scenario.

As a response to the forecasted growth of ammonia's role as a maritime fuel, two of the world's leading maritime engine manufacturers (MAN and Wärtsilä) are developing ammonia-fuelled internal combustion engines and are expecting to make them commercially available by 2024/2025.

Viking Energy is in the making to be the first carbon-free vessel running on 100% ammonia fuel by 2024. The project is led by Eidervik Offshore in partnership with Equinor. The ship will be powered by an ammonia-driven fuel cell system with a total power of 2 MW on board. During its test phase, only 60 to 70% of energy consumption will come from ammonia, the remaining being fuelled by LNG. The goal is to test the technology and the feasibility of delivering 100% carbon-free power over long distances, in this case, powered by green ammonia. The other main partners in the five-year research project are Wärtsilä, supplying the power technology and systems for ammonia storage and distribution, Prototech, supplying the fuel cell system, and NCE Maritime CleanTech, coordinating the project towards the European Union.





07

Funding opportunities

Ammonia has multiple applications which currently emit a significant amount of greenhouse gases. The production and usage of green ammonia could hence offer options in the transition to net-zero carbon dioxide emissions. However, the green premium associated with this shift is high, due to the high capital intensity of green ammonia plants. Public support is hence necessary at this initial stage to support early movers, R&D and first commercialisations, to build bankable business models and attract private investment.

7.1. EU Funding opportunities

At the European level, various initiatives have the capacity to support projects and companies engaged in greener ammonia production and usage, both at the R&D and deployment level.

7.1.1. Horizon Europe

Horizon Europe is the main EU funding R&I tool endowed with 95.5 billion EUR from 2021 to 2027 to promote EU's competitiveness and growth while boosting the Sustainable Development Goals.

The Programme supports projects across three pillars. Some initiatives from Pillar II and Pillar III are especially relevant to ammonia and are detailed below.

PILLAR 1
Excellent Science

PILLAR 2
Global Challenges and European Industrial Competitiveness

PILLAR 3
Innovative Europe

7.1.1.1. Pillar II

Pillar II covers specifically the R&I partnerships with industry, which are objective-driven partnerships between the European Commission, EU countries, industry and other relevant stakeholders. Among Pillar II 5 specific clusters, Cluster 4 'Digital, Industry & Space' and Cluster 5 'Climate, Energy & Mobility' are of specific interest for advanced manufacturing and breakthrough technologies for decarbonisation.

They can both support specific sectors covering different applications or uses of ammonia, among which for example, the demonstration of a diverse portfolio of pathways to produce synthetic renewable fuels for aviation and shipping, the use of clean ammonia in industry or for stationary power generation.

THE CLEAN HYDROGEN PARTNERSHIP OR CLEAN HYDROGEN JOINT UNDERTAKING (CHJU)

The CHJU promotes R&I activities in the European Union in clean hydrogen solutions and technologies. This private-public partnership established between Hydrogen Europe and Hydrogen Europe Research and the European Commission has a 1 billion EUR budget to allocate between 2021-2027, with an additional 200 million EUR earmarked by the recent RepowerEU communication. Ammonia production via renewable hydrogen is expected to receive increased interest in the CHP as costs of renewable energy drop. Thus, available funds for ammonia applications such as its cracking/reforming process or its use in the fuel cell systems are foreseen. Aid intensity is usually in the single-digit millions, but flagship projects can be supported with double-digit million grants.

ZERO EMISSION WATERBORNE TRANSPORT PARTNERSHIP (ZEWT)

The ZEWT is a public-private partnership between the European Commission and the Waterborne Technology Platform (WTP)[36], an industry association with members from both maritime and inland navigation countries, from 17 EU Member States, the United Kingdom, Norway and Turkey. The ZEWT has been designed to hasten and procure the introduction of clean ships, operating on renewable energy supplies. Through this partnership, the EU will fund the assessment of many alternatives to diesel bunkering, such as hydrogen and ammonia for use in Internal Combustion Engines and as a hydrogen energy carrier for fuel cells. The ZEWT overall mobilisation of resources is estimated to be 3.8 billion EUR (including a total grant budget contribution from the European Commission of up to 530 million EUR).

PROCESS4PLANET (P4P) PARTNERSHIP

The P4P is a public-private partnership established between A.SPIRE and the European Commission, which mission is to catalyse the extensive decarbonisation of European process industries. Endowed with an overall budget of 2.6 billion EUR (among which 1.3 billion EUR in grants from Horizon Europe), P4P will support emerging technologies and the scaling up of higher TRLs solutions to deliver expected CO2 emission reductions by 2030.

The partnership will focus on specific sectors, among which refining, cement, steel and chemicals, under which ammonia and ethylene processes are prioritised, due to their high CO2 emissions. It will support innovative technologies for the integration of electricity, energy efficiency and waste energy re-use. For example, the Partnership funding plan mentions electrochemical ammonia conversion, ammonia in furnaces and gas turbines, cracking, or dehydrogenation of ammonia to hydrogen.

36 / https://www.waterborne.eu/

Table 3: PAST & FORTHCOMING CALLS UNDER THE CHJU AND ZEWT PROGRAMME.
Source: HYDROGEN EUROPE'S ELABORATION. SOURCE: CHJU; ZEWT.

Date	Programme	Call	Max Grant
2022	Clean Hydrogen Partnership	Ammonia to Green Hydrogen: efficient system for ammonia cracking for application to long distance transportations	3 M EUR
2022	Clean Hydrogen Partnership	Ammonia powered fuel cell system focusing on superior efficiency, durable operation, and design optimisation	4 M EUR
2021	Zero Emission Waterborne Transport	Proving the feasibility of a large clean ammonia marine engine	10 M EUR
2021	Zero Emission Waterborne Transport	Enabling the safe and efficient on-board storage and integration within ships of large quantities of ammonia and hydrogen fuels	10 M EUR

7.1.1.2. Pillar III

Addressing innovation performance, transfer and scaling up, the Pillar III supports breakthrough solutions, including ammonia innovative applications, through the action of the European Innovation Council (EIC).

EUROPEAN INNOVATION COUNCIL (EIC): EIC PATHFINDER, EIC TRANSITION & EIC ACCELERATOR

The EIC, with a budget of 10.1 billion EUR for the period 2021-2027, leads 3 programmes: the EIC Pathfinder supporting the exploration of disruptive ideas, the EIC Transition, funding the development of innovative ideas, and the EIC Accelerator, supporting SMEs and Start-ups to scale-up their projects.

The aid intensity in grants ranges from up to 2.5 million EUR to up to 4 million EUR, whereas the equity support can be as high as 15 million EUR. On top of open calls, specific challenges for various applications, including ammonia solutions, are organised.

For example, the EIC Pathfinder 2022 workplan includes a challenge on the carbon dioxide and nitrogen management and valorisation that can be reused as feedstock for added-value products or biological fixation into agriculture, as ammonia. One of the EIC Accelerator challenges focuses on ground-breaking technologies to meet the Fit for 55 goals which involve the decarbonisation of hard to abate industries by further developing for example CO2 capture/conversion, the use of renewable hydrogen, and valorisation of by-products for co-production of energy and materials as ammonia.

7.1.2. The ETS Innovation Fund (ETS IF)

The Innovation Fund is one of the world's largest funding programmes for demonstration of innovative low-carbon technologies. The revenues for the IF are provided by the EU Emission Trading System, and the total budget of the ETS IF (at current ETS carbon prices) is around 25 billion EUR for 2020-2030.

The technologies covered by the Fund include:

- Innovative renewable energy projects;
- Carbon Capture Use and Storage (including "blue" hydrogen production);
- Energy storage (including power-to-gas projects);
- Decarbonisation of energy intensive industries (including low carbon hydrogen production for feedstock, heating, industrial or mobility applications).

The Fund supports up to 60% of relevant costs of projects through grants. In case of large-scale projects (>7.5 million EUR in CAPEX), the relevant costs are the net extra costs (CAPEX and OPEX) linked to the implementation during the 10 years after project's entry into operation. In case of small-scale projects (between 2.5 million EUR and 7.5 million EUR in CAPEX), the relevant costs are defined as the project's capital expenditure (CAPEX).

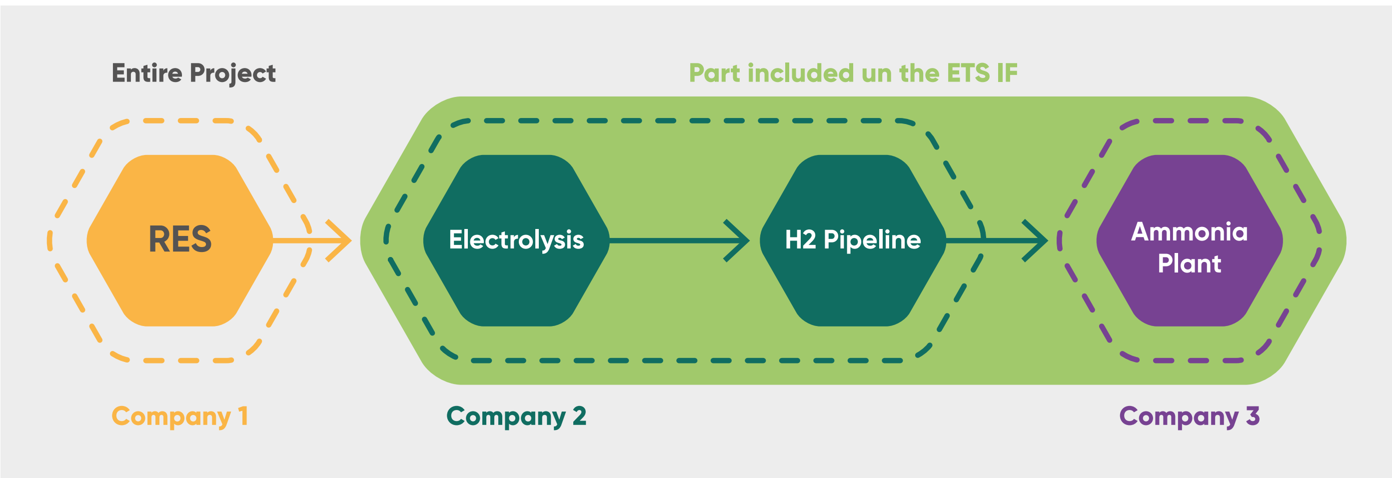
This Fund represents a big opportunity for the ammonia sector as it is open to projects for breakthrough technologies for all energy intensive industry sectors covered by Annex I to the EU Emission Trading System Directive, including the production of ammonia. It also supports all types of clean hydrogen production projects as well as end use of clean hydrogen (or clean hydrogen-based products, like e-fuels) in all kinds of sectors of the value chain.

Projects applying for Innovation Fund support will be evaluated based on the following award criteria:

- Degree of innovation;
- Greenhouse gas (GHG) emission avoidance potential and Project maturity;
- Scalability;
- Cost efficiency.

The calculations of GHG emission avoidance should cover the impacts from the changes in inputs, processes, and products between a reference scenario and the project. The reference scenarios should reflect the current or expected state-of-the-art GHG emissions that would occur in the absence of the project in the different sectors. For ammonia production, various reference scenarios can apply depending on the project structure.

Figure 40: ETS IF PROJECT BOUNDARIES.
Source: DG CLIMA.



For example, in the Diagram below, Companies 2 and 3 jointly submit a project to produce renewable hydrogen to make ammonia, replacing hydrogen from a steam methane reformer in the existing ammonia plant. In that case, the project can be defined as a modification to the ammonia plant, as the hydrogen production unit is only part of the production system. In this specific case, the reference scenario may be the emissions of the existing ammonia production plant.

Secondly, Company 3 could propose the project alone. The shift to renewable hydrogen would hence constitute a change in input for Company 3, instead of a modification to an existing production system. In this case, the reference scenario would be the EU ETS benchmark for ammonia.

Finally, if Company 2 applied alone, the principal product would be hydrogen, and the reference scenario the EU ETS benchmark for hydrogen.

In the 2021 first call for large scale projects, among the 7 projects awarded, the Kairos@C carbon capture and storage system located in Antwerp, Belgium will receive 356.9 million EUR in grants. The integrated multi-feed capture scheme, planned to enter operation in 2023, will integrate CO2 capture and purification from five diverse sources located in the Zandvliet industrial complex, including an ammonia (NH3) plant. The CO2 will then be liquefied and shipped towards CO2 subsea storage in the North Sea.

In addition to the regular general decarbonisation window (which covers CCS technologies, including for ammonia decarbonisation), the ETS Innovation Fund has opened dedicated calls under new specific REPowerEU windows which cover (1) innovative electrification and hydrogen applications in industry, (2) innovative clean tech manufacturing, and (3) mid-sized pilot projects for validating, testing and optimising highly innovative solutions. Additionally, the funding available for the 2022 Large Scale Call has been doubled to around 3 billion EUR. REPowerEU also plans to provide the ETS IF with the capacity to help projects fund the green premium associated with renewable hydrogen use and production through the deployment of carbon contracts for difference. The first RepowerEU window and the CCfDs schemes could bring additional support to various applications of ammonia.

7.1.3. Connecting Europe Facility (CEF)

The Connecting Europe Facility (CEF) is a key EU funding instrument to promote growth, jobs and competitiveness through targeted infrastructure investment at the European level. Over the period 2021-2027, CEF is endowed with 33.71 billion EUR, divided into its three main sectors of action: transport (25.81 billion EUR), energy (5.4 billion EUR) and digital (2.07 billion EUR).

CEF for Transport (CEF-T) contributes to the implementation of the Trans-European Transport Network (TEN-T) framework by financing key projects to upgrade infrastructure and remove existing bottlenecks whilst also promoting sustainable and innovative mobility solutions. CEF-T supports several actions which can be indirectly relevant to the ammonia sector, including infrastructure projects on the Core and Comprehensive TEN-T (roads, inland waterways, maritime and inland ports, among others) whose priority comprises the development of zero or low emission multimodal solutions.

Furthermore, CEF-T Alternative fuels infrastructure Facility (AFIF), with a total budget of 1.5 billion EUR, has the capacity to fund HRS supplying liquid or gaseous hydrogen at pressure of 350 bar and/or 700 bar. It can support the extra cost as well associated to inland and short sea shipping vessels propelled by hydrogen or hydrogen carrier fuels (e.g., ammonia), if it is demonstrated that an initial number of vessels is needed to kick-start the use of the supported refuelling infrastructure.

7.1.4. Renewable and Low-Carbon Fuels Value Chain Industrial Alliance (RLCFA)

The RLCFA is a new initiative which focuses on boosting production and supply of renewable and low-carbon fuels in the aviation and waterborne sectors to support the FuelEU Maritime and RefuelEU Aviation initiatives. The Alliance is a voluntary collaboration of stakeholders active in the transport fuels industry, from sourcing to end-users, as well as technology and finance providers.

The European Commission has established a Steering Group with representatives of DG Move, Safran and Fincantieri as respective chairs of the aviation and waterborne chambers, and Hydrogen Europe and FuelsEurope, as Members of the Alliance Secretariat, to launch the works of the Alliance.

Considering the potential of ammonia in the decarbonization of the maritime sector, RLCFA will dedicate special attention to ammonia as a sustainable fuel.

7.1.5. European Investment Bank (EIB)

Over the past eight years, the EIB has provided over 550 million EUR in direct financial support related to hydrogen technologies, mobilising over 1.2 billion EUR in overall investment. The EIB has several financing tools already available as the InnnovFin Energy Demo Projects or the Future Mobility initiative to address key challenges of hydrogen projects and related applications. These tools can provide blended support to electrolyser manufacturing, catalysts production and fuel cell development as well as large-scale hydrogen production, all critical components of green and low carbon ammonia projects.

The EIB has also agreed in 2021 to further expand cooperation with the Japan Bank for International Cooperation (JBIC) on a range of globally relevant investments across the globe. This includes identifying co-financing opportunities for infrastructure connectivity and projects contributing to carbon neutrality in the European Union, such as offshore wind plans, battery storage facilities and hydrogen technology development that could promote the ammonia sector. Following the Japan Post Covid Growth Facility, calling for an intense decarbonisation process, the JBIC has started to greatly provide loans or equity to support Japanese companies in the development of supply chain-type green and blue fuel ammonia production projects.

7.2. Other support schemes

Additional to general EU funding and financing initiatives, extra support for the scale up of green technologies is often provided at the Member State level, under the framework of State Aid.

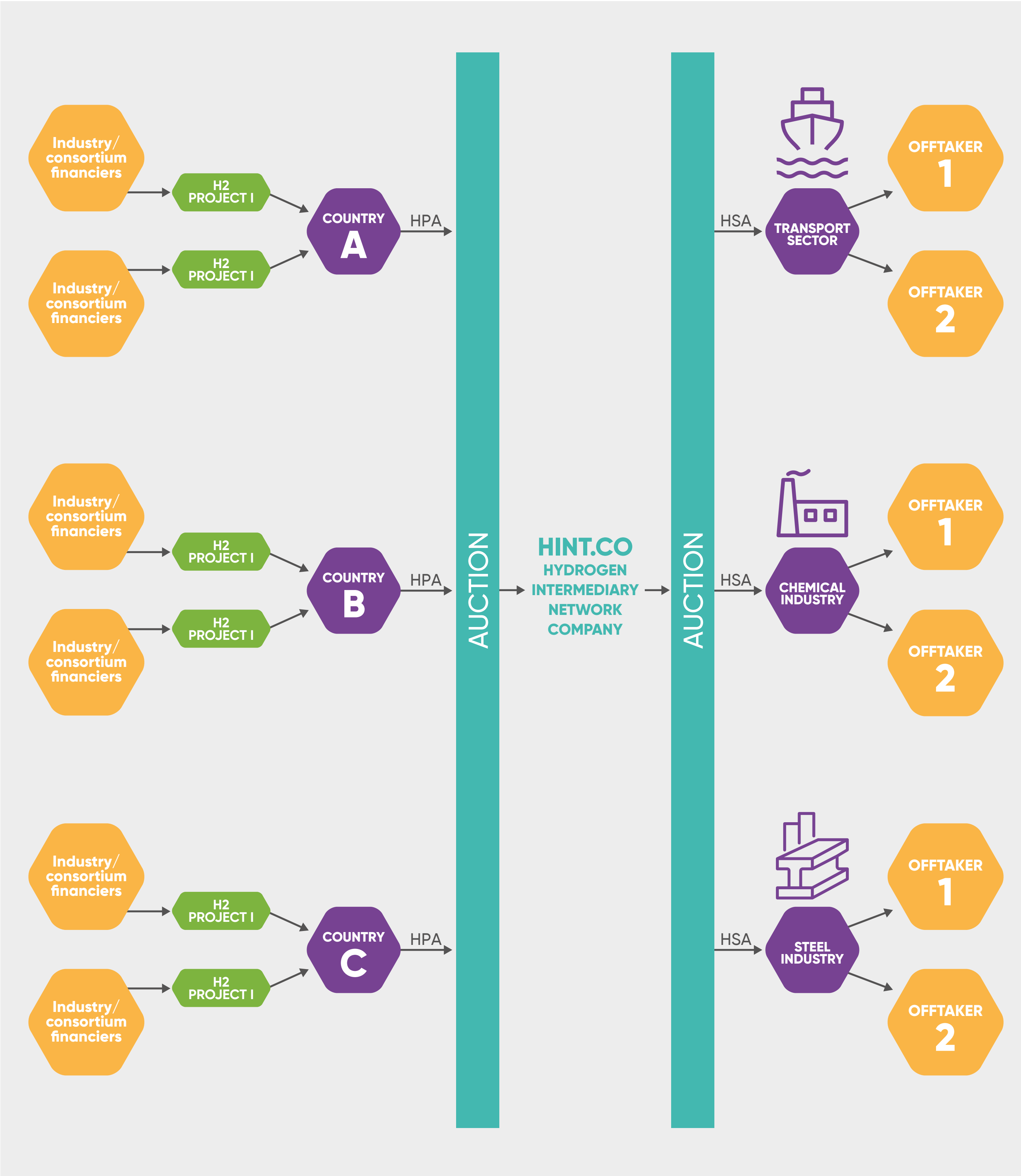
7.2.1. Focus on Germany and H2 Global

The H2 Global Initiative is a support mechanism which role is to advance the international market ramp-up of green hydrogen and its derivates such as ammonia, methanol, and sustainable aviation fuel by using a double-auction model. A dedicated intermediary, the Hydrogen Intermediary Network Company GmbH (HINT.CO), will conclude long-term purchase contracts on the supply side and short-term sales contracts on the demand side for green hydrogen and PtX products. In analogy to the Contracts for Difference (CfD) approach, the difference between supply prices (production and transport) and demand prices will be compensated by HINT.CO, which will be funded by various funding bodies.

The Funding source for H2 Global first funding window is the German Federal Ministry for Economic Affairs and Climate Action (BMWK), which will provide 900 million EUR to the initiative. In line with the objectives of the German government's economic stimulus program, this first program will focus at establishing foreign trade partnerships with countries in which green hydrogen can be produced efficiently due to their geographical location. Green technologies will be hence established in partner countries where the local energy transition will be supported, while a contribution will be made to meet the massive demand for PtX products in Germany and Europe.

In December 2022 H2Global has announced the first 3 tenders to supply renewable ammonia, methanol and sustainable aviation fuels (SAF) in a 10-year contract,, with a first cargo expected between 2024-2026. The potential value of the renewable ammonia contract is 380 million EUR.

Figure 41: GERMANY'S HINT.CO TO AUCTION HYDROGEN IMPORTS.
Source: H2GLOBAL.



Note: HPA = Hydrogen Purchase Agreement, HSA = Hydrogen Service Agreement.

7.3. Private finance

One of the main challenges for hydrogen project regarding bankability is the securing of long-term, offtake scheme, due to the still limited demand for the molecule. Existing use cases for hydrogen such as ammonia are among the first green hydrogen related opportunities to be attractive for private investors, due to an existing ammonia market and its relative ease of transportation.

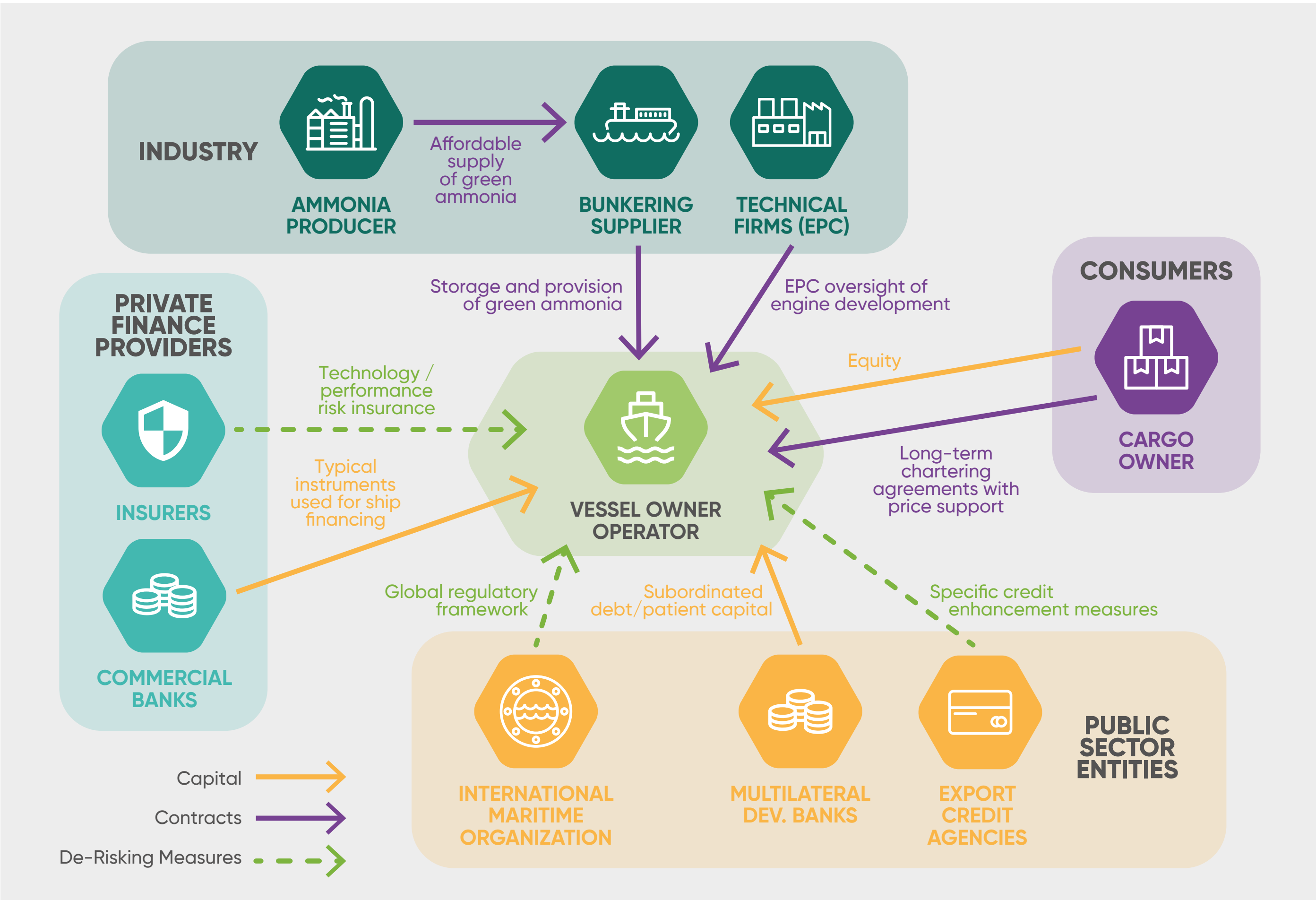
7.3.1. The Financing the Transition to a Net-Zero Future initiative (FTT)

The FTT is a collaboration between the World Economic Forum and management consulting company Oliver Wyman launched in 2020 to identify solutions that would accelerate financing towards innovative breakthrough technologies in key hard-to-abate sectors.

The initiative sits within the Mission Possible Partnership (MPP) Finance Hub and relies on industry collaboration through its sector verticals, with more than 50 leading financial institutions participating. The FTT's mission is to steer capital toward prioritised breakthrough technologies for their impact on industrial decarbonisation:

- Sustainable aviation fuels for Aviation;
- Carbon capture and storage and Hydrogen-based direct reduced for Steel;
- Ammonia for shipping.

Figure 42: ENABLING SHIPPING DECARBONIZATION. DEAL STRUCTURING AND FINANCING BLUEPRINT FOR GREEN AMMONIA-POWERED SHIP.
Source: WORLD ECONOMIC FORUM AND OLIVER WYMAN, BASED ON INDUSTRY INPUT.



7.3.2. Yara Growth Ventures (YGV)

Yara Growth Ventures is the corporate venture capital team of Yara International ASA, one of the largest manufacturers of ammonia in Europe. The team has the mandate to invest in tech-based start-ups, with a sweat spot in Series A and B, and ticket size between USD 1-5 million (average ticket is USD 3 million). YGV invests globally in the hydrogen/ammonia and agri-tech space, has an annual budget of USD 25 million and a multi-annual frame of USD 100 million. The investment thesis focus on companies offering breakthrough performance for high efficiency and low-cost hydrogen (e.g. Next generation High efficiency electrolysers and hydrogen separation units), novel solutions in ammonia technologies and applications (e.g. production, cracking and end-use). YGV will have the capacity to co-invest with Yara's new business unit Yara Clean Ammonia with the goal to accelerate the development of green ammonia, not only in the fertiliser sector but also as fuel and for power generation.

YGV has invested in H2Pro, Hydrogen Mem-Tech, but also as a limited partner in AP Ventures dedicated hydrogen fund (APV fund II).

7.3.3. AP Ventures

AP Ventures is headquartered in London and manages venture capital funds with a global mandate to invest in pioneering technologies in hydrogen production, storage, transportation as well as hydrogen applications in sectors including mining, transportation, and heavy industry. Their current 300 million EUR fund invests in high growth seed and Series A for up to 5 million EUR, with the possibility to follow on.

AP Ventures investors include Yara, Anglo-American Platinum, Impala Platinum, the Mirai Creation Fund, Mitsubishi Corporation, Plastic Omnium, the Public Investment Corporation and Sumitomo Corporation.

The existing portfolio is focused on the entire hydrogen value chain and includes investments in C-Zero, ERGOSUP, Greyrock Energy, Hydrogen Refueling Solutions, HyET, Hydrogenious, Infinium, Plug Power, and ZEG Power. In the ammonia sector, AP Venture has invested among other in Starfire Energy, which leverages a patented catalysis technology that allows for the synthesis and cracking of carbon-free ammonia, and Amogy, which has developed clean ammonia-to-power technology for shipping and other transportation applications.

7.3.4. Copenhagen Infrastructure Partners (CIP)

CIP is a Danish fund management company focused on renewable energy infrastructure with around 14 billion EUR in a commitment under management. The company is moving fast in the ammonia sector as the following projects demonstrate.

In 2021, CIP has signed a memorandum of understandings (MoU) for the establishment of Europe's largest production facility (1GW electrolysis) of CO2-free green ammonia. The project will be located in the town of Esbjerg on the west coast of Denmark, where the Power-to-X-facility will convert power from offshore wind turbines to hydrogen and then ammonia. Ammonia will be used by the agriculture sector as CO2-free green fertiliser and by the shipping industry as CO2-free green fuel.

In 2022, the fund management has announced a partnership with Enagás, Naturgy, Fertiberia and Vestas to build a project for the large-scale production of green hydrogen and ammonia in Spain. The project will bring emissions reductions of 1 million tons of CO2e per year in its first phase, and up to 2.5 million tons per year when it reaches full implementation[37].

37 / For more information: February 1, 2022 - Copenhagen Infrastructure Partners (cipartners.dk).

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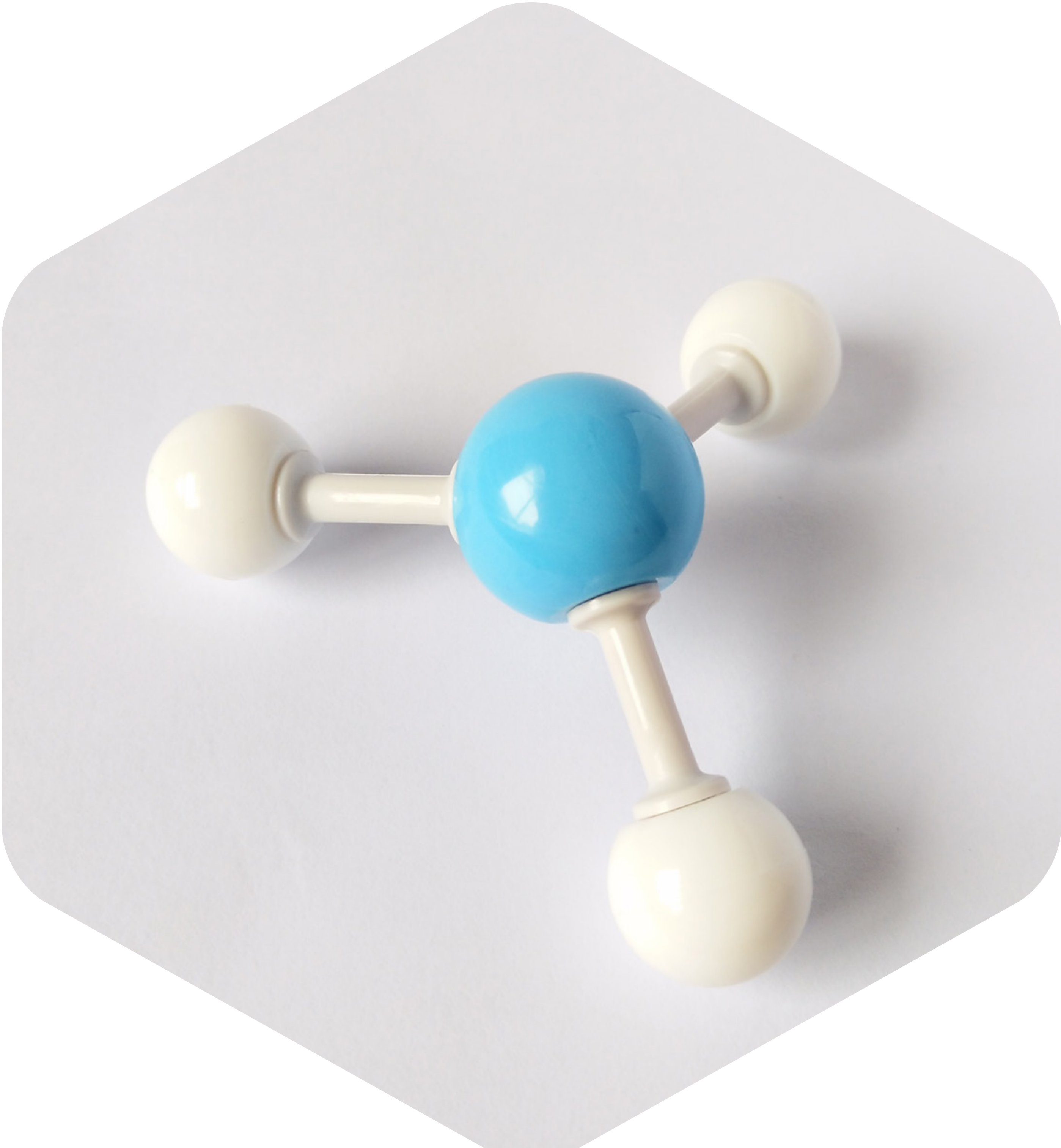

Hydrogen Europe