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Fertilizer industry exploitation study: Techno-economic analysis of electrolysis based ammonia production for the fertilizer industry

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## Executive Summary

The reduction of greenhouse gases to limit global warming and mitigate the risks of climate change requires major changes in the energy system. Green hydrogen, produced from water electrolysis using renewable electricity, is expected to play an important role in the transition towards a sustainable net-zero energy system.

H2FUTURE is a European flagship project, which aims to further the technology development of water-electrolysis for green hydrogen production. This particular study is part of task 9.3 of work package 9 (WP9) which focuses on the techno-economic evaluation of the use of electrolysis in one of the most important industrial applications: the synthesis of ammonia for fertilizers. The aim of this work is to determine under which technical, cost and environmental conditions the replacement of conventional hydrogen production by water-electrolysis can be a competitive alternative for the ammonia industry.

Ammonia ( $\text{NH}_3$ ) is one of the most commonly produced industrial chemicals. Global production amounts to 180 million tons of  $\text{NH}_3$  per year. Approximately 70% of produced ammonia is used to make fertiliser products, of which urea is the most common end-product [1]. When evaluating pathways for decarbonization of ammonia, it is important to take into account that subsequent urea synthesis requires  $\text{CO}_2$  as feedstock. Currently, the  $\text{CO}_2$  produced during natural gas reforming is used, but an alternative  $\text{CO}_2$  source would be necessary if reforming is replaced by electrolysis.

In this study, five different plant configurations for ammonia production are analysed and compared. The key difference between the configurations lies in the method of hydrogen production. The conventional process based on natural gas reforming is compared to the same process including CCS and 100% electrolysis. Additionally, two 'hybrid' plant configurations are analysed, in which the reforming process is only partially substituted with electrolysis, in order to use the  $\text{CO}_2$  from the reforming step for urea production. For all five cases, the mass balances and the costs are modelled.

In order to determine under which conditions electrolysis-based ammonia production can be a competitive alternative to the conventional process based on natural gas reforming, the break-even electricity price was calculated. This is the value for which the levelised cost of ammonia (LCOA) using hydrogen from electrolysis is equal to the LCOA using hydrogen of the steam reforming process. Over time, the break-even electricity price for the hybrid and electrolysis cases increases, due to the expected increase in natural gas prices and  $\text{CO}_2$  emissions prices over the coming decades, as well as expected decrease in investment costs for electrolysers. For the short term, the results of break-even electricity price calculations are still below expected LCOE levels of solar and wind power generation. This points to a challenging business case for electrolysis based ammonia production. However, the break-even electricity price for new plants to be built in the period 2030-2040 is expected to be comparable to or even higher than the cost level of renewable electricity, showing a clear prospect for a transition to competitive production of ammonia from renewable hydrogen. At high natural gas and  $\text{CO}_2$  prices and at locations with optimal sun and wind conditions, this can be the case even earlier.

However, if CCS is possible and allowed and a switch to the fossil-based low-carbon hydrogen option is made first in view of rising  $\text{CO}_2$  prices, then a switch to renewable hydrogen at a later stage seems more challenging. A  $\text{CO}_2$ -price mechanism alone provides insufficient incentive for the deployment of green hydrogen in ammonia production if existing ammonia production plants are first equipped with CCS. Other incentives are then needed for transitioning all fossil hydrogen based ammonia production to production with renewable hydrogen. Sensitivity analysis of the business case shows

that if the natural gas price would increase to a level of approximately 40 €/MWh, the switch to electrolysis-based renewable hydrogen becomes much more attractive, even when compared to the CCS option, especially in combination with expected decrease in investment cost of electrolysis in the 2030-2050 timeframe.

Converting existing ammonia production capacity from natural gas reforming to electrolysis requires a large amount of near-zero-emission electricity, in order to lead to a reduction in CO<sub>2</sub> emissions. This transition would place a fairly large burden on current electricity production in the countries where ammonia production is currently located. Furthermore, the electricity demand for electrolysis-based ammonia production would require a significant share of the projected capacities of solar and wind power production in the EU28. Especially, considering the additional demand for zero-emission electricity from other major electrification options such as electrical boilers in the industry, electric vehicles and residential heat pumps. Next to the limited supply of zero-emission electricity, infrastructure and land-use constraints can pose a challenge for the production of green hydrogen in Europe. It is possible that future hydrogen demand will be met by importing it, rather than producing it locally or that ammonia production would be relocated to countries with more abundant renewable energy production capacity and infrastructure.

For the ammonia industry to become completely decarbonized, all three sources of CO<sub>2</sub> emissions must be addressed: direct emissions from steam methane reforming, indirect emissions from urea use in agriculture and indirect emissions from electricity generation for electrolysis. The direct emissions can be reduced by (partially) substituting hydrogen production from natural gas reforming, by electrolysis or by implementing CCS. The indirect emissions from urea use can be reduced by (1) using a climate neutral source of CO<sub>2</sub> for urea synthesis, in combination with hydrogen from water-electrolysis, (2) by making more efficient use of the fertilizer, so less urea needs to be applied to soil or (3) by eliminating urea use entirely by transitioning to other nitrogen-based fertilizers, such as ammonium nitrate. The indirect emissions from electricity generation can be eliminated by making use of a zero-emission source of electricity. To arrive at a fully sustainable zero-emission electricity system, further expansion of renewable electricity supply is clearly needed in many of the EU28 countries.

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# 1 Introduction

## 1.1 Background

In order to keep the negative impacts of climate change within acceptable limits, the goal set in the Paris Climate Agreement is to limit global warming to well below 2, preferably 1.5 degrees Celsius, compared to the pre-industrial level. At present, global warming is already 1.1 degrees Celsius and greenhouse gas emissions have not yet shown a structural decline. There is therefore an enormous challenge to reduce greenhouse gas emissions to net-zero as quickly as possible, after which a period of negative emissions is probably also necessary. This requires major changes in the energy system and in the use of fossil energy as a raw material for the chemical industry.

### 1.1.1 The importance of renewable, green hydrogen

Many influential reports have recently been published that emphasize the importance of green hydrogen for achieving a clean sustainable net-zero energy system [2] [3] [4] [5]. Green hydrogen is hydrogen obtained by splitting water with electricity produced with energy from the sun and wind. The process of splitting water using electricity is known as water electrolysis.

By splitting water using electricity generated from the sun and wind, the energy from those sources is, on balance, captured as chemical energy in hydrogen. The renewable energy sources solar and wind thus become available in the form of a gaseous carbon-free energy carrier. Due to the versatile application possibilities that hydrogen offers, this greatly increases the deployability of the solar and wind sources. This is very important because these are the most abundantly available renewable energy sources we have.

### 1.1.2 The systems role of green hydrogen

Green hydrogen has a storage function if it is used for conversion back to electricity via fuel cells, gas turbines or gas engines. It can also replace natural gas for the production of high-temperature process heat in industrial processes, and possibly also for space heating in the built environment. It can also serve as a fuel for fuel cell electric vehicles, ranging from cars to trains, ships and possibly even airplanes.

In addition to the energetic use of green hydrogen, it also has a number of important non-energy applications. In the first place, it can be used as a replacement for the current industrial hydrogen. It is currently produced on a large scale using fossil fuels. The largest amounts are currently used for the production of ammonia and the refining of crude oil. Furthermore, green hydrogen (in combination with sustainable sources of carbon) can serve as a chemical building block for the production of synthetic liquid fuels (diesel, kerosene), and products in the chemical industry (methanol, olefins and further to plastics, etc.). Finally, green hydrogen can be used as a reducing agent in fully hydrogen-based low-carbon processes for the production of iron and steel.

In summary, the essence of green hydrogen is that it offers an extra option, in addition to renewable electricity, to make the energy from the sun and wind sources available in a usable way for a clean and sustainable energy system. It can be used for a wide range of energy applications that are difficult or impossible to electrify. In industry, it can be used non-energy in many processes with greenhouse gas emissions that are otherwise hard-to-abate, and as a renewable building block for synthetic hydrocarbon products. In addition, at the level of the global energy system, green hydrogen

can facilitate the exchange (export/import) of energy between areas with an abundance of renewable energy sources and areas with limited availability of those resources.

### 1.1.3 Water-electrolysis is a key technology

In this perspective on a clean and sustainable energy supply, water-electrolysis is a key technology. Although the technology is not new, significant improvements are still needed before the technology can fulfil the large-scale role in the energy system that is envisioned. It is important that the electricity consumption per unit of hydrogen is reduced as much as possible and that the service life of the technology is extended as much as possible. It is also important that the possibilities for dynamic operation are improved in order to function properly in energy systems that are increasingly based on a variable supply of energy from sun and wind. The ability to quickly adjust the power level at which an electrolysis unit is running offers a lot of flexibility through options for demand response. The flexibility that water electrolysis offers therefore applies not only to the integration of solar and wind energy via hydrogen, but also to the controlled integration of the variable supply of electricity from those sources (two sides of the same coin). However, the deployment for demand side management services should not be at the expense of efficiency and the longevity of the technology. Optimization of systems and new system designs, use of cheaper materials, scaling up supply chains for the technology with increasing competition, and economy of numbers and scale should further ensure the necessary reduction in the investment costs and the fixed maintenance costs of the technology.

## 1.2 The H2FUTURE Project

The H2FUTURE project is part of the electrolysis technology development trajectory that is taking place. Central to the project is the demonstration of a 6 MW water electrolysis installation. This installation is based on the latest polymer electrolyte membrane (PEM) electrolysis technology of Siemens. The technology is being put into practice for the first time in a complete system in this project. The installation will be realized and tested on the site of the voestalpine steel plant in Linz, Austria. This fits with voestalpine's expectation that a hydrogen-based Direct Reduction (DR) process in combination with an Electric Arc Furnace (EAF) will become the dominant technology for steel production in the future. In order to prepare for this, voestalpine wants to get to know the technology and at the same time assess the state of development of the technology. The project is coordinated by the Austrian utility Verbund, which also wants to gain experience with the technology and is interested in the ability of the technology to respond in a timely manner to price incentives from the market and provide services to support integration of intermittent power sources and the balancing of the power grid. With the view of deployment of the technology for delivering grid services, APG, the Austrian TSO, is also a partner in the project.

The larger part of the H2FUTURE project is related to the design, engineering, building, commissioning, testing, actual operation, and monitoring of the demo-plant. Next to the experimental program, the H2FUTURE project includes a work package that focuses on determining the key performance indicators of the electrolysis system and the techno-economic evaluation of the use of electrolysis in two of the most important industrial applications, i.e. the production of iron and steel and the synthesis of ammonia for fertilizers.

The application of green hydrogen for ammonia production could help reduce the industry's heavy reliance on fossil fuels and large carbon footprint. Worldwide, ammonia production emits around 450 Mt of CO<sub>2</sub> [1]. Ammonia synthesis is particularly emissions intensive, with 2.4 tonnes of CO<sub>2</sub> emitted

per ton of ammonia produced. This is about one and a half times as emissions intensive as crude steel production and four times as intensive as cement production, based on direct emissions [1]. Ammonia production accounts for around 20% of energy consumption of the wider chemical sector and around 35% of its CO<sub>2</sub> emissions [1].

### 1.3 Goal and scope of the document

This report is part of the deliverables of work package 9 of the H2FUTURE project and deals with the analysis of the use of hydrogen produced via electrolysis for the production of ammonia. The aim of the study is to determine under which technical, cost and environmental conditions replacement of natural gas based hydrogen production by hydrogen production through water-electrolysis can be a competitive alternative for the synthesis of ammonia. This report presents the results of the study with a focus on the former EU28.

### 1.4 Reading guide

The next chapter first sketches a picture of the use of hydrogen for the synthesis of ammonia and the application of ammonia worldwide. In addition, the chapter presents an overview of ammonia production in the former EU28. Chapter 3 describes the alternative plant configurations that have been considered and analysed. The chapter also presents an overview of the assumptions and parameters that have been used in the analysis. Chapter 4 contains the results and discussions. Section 4.1 describes the break-even electricity cost at which electrolysis becomes competitive for ammonia synthesis and shows the sensitivity to changes in various parameters. In Section 4.2, the need for renewable electricity in the various EU countries where ammonia production takes place is discussed. In Section 4.3, different sources of CO<sub>2</sub>-emissions for ammonia production are detailed and the emissions of different process schemes are analysed. Finally, Chapter 5 presents the conclusions of this study.

### 1.5 Notations, abbreviations and acronyms

Table 1. Acronyms list

ATR	Autothermal reformer / reforming
ASU	Air separation unit
BFD	Block flow diagram
CAPEX	Capital expenditure, investment
CCS	Carbon capture and storage
DR	Direct reduction
EAF	Electric arc furnace
ETS	Emissions trading system
EU	European Union

EU 28	28 member states of European Union (until 2020), including United Kingdom
EU 27	27 member states of European Union (after 2020), excluding United Kingdom
GHG	Greenhouse gas
HRU	Hydrogen recovery unit
HHV	Higher heating value
IEA	International energy agency
LCOA	Levelised cost of ammonia
LCOE	Levelised cost of electricity
LHV	Lower heating value
O&M	Operation and maintenance
OPEX	Operational expenditure
PEM	Polymer electrolyte membrane
PV	Photovoltaic
UK	United Kingdom
SMR	Steam methane reforming
Tpd or t/d	Ton (1000 kg) per day
TSO	Transmission system operator
WACC	Weighted average cost of capital
WGS	Water gas shift

Table 2. Molecules list.

CO <sub>2</sub>	Carbon dioxide
H <sub>2</sub>	Hydrogen
NH <sub>3</sub>	Ammonia
N <sub>2</sub>	Nitrogen
NO <sub>x</sub>	Nitrogen oxides (can refer to NO or NO <sub>2</sub> )
(NH <sub>2</sub> ) <sub>2</sub> CO	Urea
NH <sub>4</sub> NO <sub>3</sub>	Ammonium nitrate

## 2 Ammonia and fertilizer industry

### 2.1 Global production and trade of ammonia production

Ammonia (NH<sub>3</sub>) is one of the most commonly produced industrial chemicals. It is the basis of many chemicals and very importantly the first step in producing (nitrogen-)fertilizers. According to the IEA, global production increased by 50% from 1990 to approximately 183 million tons in 2019 [1]. Since 1975, production has even tripled. In recent years, however, production has been stable at the level of around 180 million tons, although a further increase is expected in the future. Approximately 16 million tons are produced in Europe, which is almost 9% of global production [6].

Most of the ammonia produced, currently almost 90%, is directly processed further at production locations. The rest is traded and is often transported over great distances. The traded amount has been at the level of 18 to 20 million tons annually in the past decade [1].

### 2.2 Applications of ammonia

Ammonia is mostly used in the manufacture of fertilizers such as urea and ammonium nitrate. An overview of the production of main fertilizer products is shown in Figure 1. Estimates of the share of ammonia that is used for fertilizers range from 70% to 90%. This is probably due to a difference between direct and indirect use of ammonia for fertilizers. Part of the ammonia is first used for the production of nitric acid before it is processed into a fertilizer product. Figure 1 shows an overview of the main fertilizer products and intermediates. But industrial uses may include the production of nitric acid, most of which eventually also ends up in fertilizer products. The IEA estimates the share of ammonia used for fertilizer at about 80%.

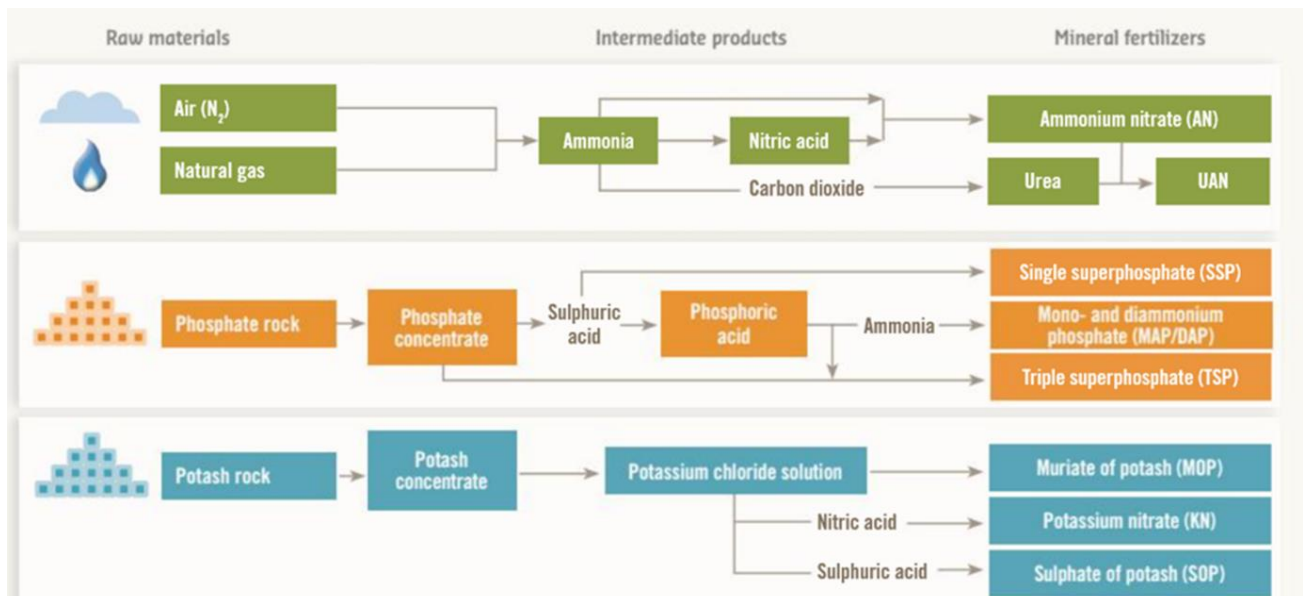


Figure 1: Overview of the main fertilizer products [7].

The part of ammonia that does not go to fertilizer is used for industrial applications such as explosives, synthetic fibres and plastics (e.g. polyamides, synthetic rubbers and melamine) and other specialty materials (e.g. resins, medicines, cosmetics), which are an increasingly important source of demand.

## 2.3 Urea, and the need for CO<sub>2</sub> in ammonia industry

Within the different types of nitrogen fertilizers, the largest part is formed by urea-based products. Urea, chemical formula CO(NH<sub>2</sub>)<sub>2</sub>, is also an important intermediate step in the production of the plastic melamine and urea-formaldehyde resins. In addition, it has a wide range of applications, such as in the reduction of NO<sub>x</sub> emissions in exhaust gases from diesel trucks, as a means for de-icing aircraft, and as an ingredient in cosmetics and many medical and personal care products (shampoo, toothpaste, etc.). About 48-56% of the ammonia globally produced is used for subsequent production of urea. This is an important aspect to take into account when considering the options for replacing current hydrogen production for ammonia based on fossil fuels with hydrogen produced via water electrolysis. The reason is that urea is formed by reacting NH<sub>3</sub> with CO<sub>2</sub>. The CO<sub>2</sub> currently used for the process is the CO<sub>2</sub> that is formed at the production of hydrogen from fossil fuel. So if fossil-based hydrogen is fully replaced by electrolysis-based hydrogen at a plant where ammonia production is combined with urea production, the use of an alternative source of CO<sub>2</sub> needs to be considered as well.

## 2.4 Ammonia: an important starting point for the green hydrogen transition

The ammonia industry is the second largest consumer of pure hydrogen. According to the IEA, ammonia represented almost 43% of global hydrogen demand in 2018. Refining represented almost 52%, and “other” demands accounted for 6%. Global production of pure hydrogen in 2018 is estimated at approximately 75 million tons, of which more than 31 million tons is related to ammonia production. Hydrogen production in Europe for ammonia amounts to about 3.8 million tons of which almost 95% is based on natural gas. The amount of production in the EU, including the UK, is estimated at 3.1 million tons.

The ammonia industry thus forms a large and existing market for hydrogen. It is therefore a sector that can play an important role in initiating the transition to green hydrogen in industry and the wider energy system. Since hydrogen is a basic component for ammonia production, there are few alternative options for decarbonising the ammonia and associated urea-fertilizer industry. However, due to the still high costs, the implementation of green hydrogen is a challenge. In addition, the need for CO<sub>2</sub> and potential problems related to the availability and costs of alternative sources of CO<sub>2</sub> could pose an additional barrier to initiating the transition in the short term.

## 2.5 Ammonia industry in the (former) EU28

In the EU, the fertilizer sector produces and consumes approximately 3,1 million tons of hydrogen per annum. After a steady increase in use of nitrogen fertilizers up to more than 15 million tons (based on nitrogen content) in the '80s, there was a steep decrease in the early '90s to a level of about 11 million ton. The use of nitrogen fertilizers have been around this figure since then, and is



expected to stay at this level towards 2030, with the trend appearing to be slightly declining rather than increasing. This reflects the balance of a decrease in use in half of the countries of the former EU28 and an increase in the other half. The largest decrease in percentage terms is expected in Germany, Denmark, the Netherlands, Spain and France, and the largest increase in Eastern Europe and Baltic countries.

The EU28 has a cumulative production capacity of 56 kilotons of ammonia produced per day (21 million tons per year), which is spread over 17 different countries and 42 production plants, as shown in Table 3. The largest production capacity is located Germany, Poland and the Netherlands.

Table 3: Capacity and number of NH<sub>3</sub> production plants per country [8].

Country	Capacity	Number of plants
-	ton NH <sub>3</sub> / d	-
Germany	9419	5
Poland	8795	5
Netherlands	7444	2
Romania	5962	6
France	4096	4
Lithuania	3063	1
Bulgaria	3063	3
UK	3014	3
Belgium	2795	2
Spain	1668	3
Italy	1644	1
Austria	1329	1
Slovakia	1175	1
Hungary	1049	2
Czech Republic	959	1
Estonia	548	1
Greece	452	1
<b>EU28 total</b>	<b>56474</b>	<b>42</b>

## 2.6 Description conventional ammonia production

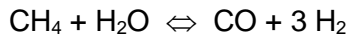
For the first time in 1913, ammonia was produced on an industrial scale with the so-called Haber-Bosch process. Since then industrial ammonia synthesis has changed very little. The only aspect that has changed, is the technology for the production of hydrogen. Initially, hydro powered electrolysis was a common source of hydrogen. However, with the increasing availability of low-cost natural gas in the 60s and 70s of the last century, the electrolysis-based plants were shut down. The Haber-Bosch process is still the dominant process for ammonia synthesis. Today, most ammonia is produced on a large-scale by the Haber-Bosch process with capacities of up to 3,300 tons per day (t/d).

An industrial plant for ammonia production consists of two major processes, i.e. the production of hydrogen and the synthesis of ammonia. While there are numerous configurations for ammonia production plants, the underlying scheme for each is the same. First hydrogen is produced and subsequently a mixture of hydrogen gas (H<sub>2</sub>) and nitrogen gas (N<sub>2</sub>) reacts over a catalyst at temperatures in the range of about 370-500°C and pressures that may vary between 100 to 250 bar.

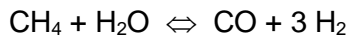
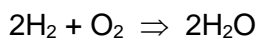
A typical modern ammonia-producing plant first converts natural gas, liquified petroleum gas, or petroleum naphtha into gaseous hydrogen. The method for producing hydrogen from hydrocarbons is known as steam reforming. Hydrogen can also be produced from oil products or coal by gasification.

Figure 2 presents a block flow diagram (BFD) of a typical ammonia plant with natural gas based hydrogen production without carbon capture and storage (CCS). This process consists of following steps:

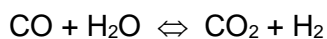
- The natural gas is pre-treated by removing and trace components that may poison the reformer catalyst, such as sulphur (process unit not shown in the BFD).
- The cleaned natural gas is fed to a two-step reformer process. The primary reformer is a steam methane reformer (SMR) where methane reacts with steam to form carbon monoxide (CO) and hydrogen.



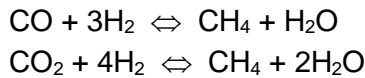
- The conversion of CH<sub>4</sub> with H<sub>2</sub>O is an endothermic reaction. The energy for the reaction is provided by external firing of the reactor which produces a flue gas. The secondary reformer is an air-blown autothermal reformer (ATR). The introduction of air in this reformer provides the nitrogen for the synthesis of ammonia. The oxygen in air reacts with hydrogen to form steam which subsequently reacts with available methane:



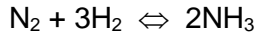
- The raw syngas leaving the reformer section mainly consists of H<sub>2</sub>, N<sub>2</sub>, CO, CO<sub>2</sub> and steam together with a small amount of CH<sub>4</sub> and traces of Argon (introduced via air). The raw syngas is first purified from CO in the CO-shift or water-gas-shift (WGS) section where CO reacts with steam in a high and low temperature part to produce CO<sub>2</sub> and H<sub>2</sub>:



- In the next section the bulk of the CO<sub>2</sub> is removed by using an absorption process with activated methyl diethanolamine (aMDEA) as a based solvent. The process mainly consists of an absorber and a solvent regeneration section. The CO<sub>2</sub> released from the solvent in the regeneration section is then sent to a downstream urea plant as feedstock for the urea production. But not all plants would be able to consume all the CO<sub>2</sub> from the removal section as most of the fertilizer complexes also produce other type of ammonia products. Thus, any surplus CO<sub>2</sub> is combined with the flue gas of the SMR and normally vented to the atmosphere. Alternatively, the combined residual gas is first sent to a unit for CO<sub>2</sub> capture (see Figure 3). The decarbonized gas is then vented through the stack and the captured CO<sub>2</sub> is further processed (drying and compression) and sent to a storage (further processing and storage not included in BFD).
- After the CO-shift and CO<sub>2</sub>-removal steps the cleaned syngas then passes through a methanation reactor. This polishing step removes any remaining CO and CO<sub>2</sub> which would otherwise poison the ammonia synthesis catalyst:



- Next the purified syngas is compressed and then sent to the ammonia synthesis loop where it is converted to liquid ammonia. The ammonia synthesis takes place at temperatures in the range of 370-500°C and pressures that may vary between 100 to 250 bar, according to the following reaction:



- In the ammonia synthesis reactor about 25-30% of the syngas is converted into NH<sub>3</sub>. As part of the synthesis loop the product gas is cooled to about 0°C in chillers where most of the NH<sub>3</sub> condenses. The liquid NH<sub>3</sub> is then separated and the remaining syngas is recycled to the synthesis reactor.
- A purge is needed to prevent accumulation of inert components, mainly CH<sub>4</sub> and argon, in the synthesis loop. The purge gas stream is first sent to a unit that recovers NH<sub>3</sub>, which is returned to the synthesis loop, and then to a H<sub>2</sub> recovery unit (HRU). The H<sub>2</sub> is recycled to the natural gas pre-treatment unit and used as feedstock. The tail gas of the HRU is used as fuel for the SMR.

Next to the hydrogen production and ammonia synthesis processes all process variants analyzed in this study include an urea synthesis unit. However, the unit is not included in the BFD as it can be considered more or less independent of the upstream processes. The urea part is the same in all process variants. Its main impact on the upstream processes is determined by its capacity relative to the ammonia plant, i.e. the share of ammonia that is needed to produce the urea.

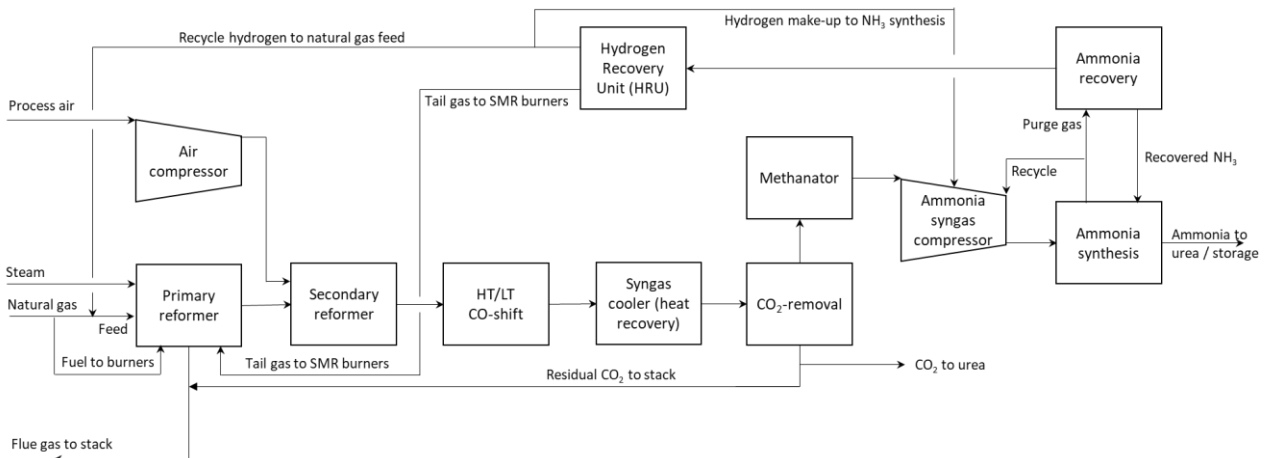


Figure 2: Simplified block flow diagram of a conventional ammonia plant without CCS.

## 3 Techno-economic model of low-carbon ammonia production processes

The following chapter describes the methodology that is used to model different plant configurations for ammonia production. First, five different process configurations and their characteristics are described. Next, the method and inputs used to calculate the costs of each process are explained. The goal of this techno-economic analysis is to determine under which technical, cost and environmental conditions electrolysis-based ammonia production can be a competitive alternative to the conventional process based on natural gas reforming.

### 3.1 Plant configurations

For study purposes an ammonia plant with a capacity of 1350 t/d is taken as the starting point, which is approximately the average ammonia production plant capacity in the (former) EU28 [8]. This value corresponds to the capacity used in a detailed design study for an integrated ammonia/urea plant carried out within the framework of the IEAGHG program [9]. Hence, this enables the use of the results of the IEAGHG study for the purposes of this analysis. However, unlike the IEAGHG study, we do not assume complete conversion of ammonia to urea, but conversion of only 52% of the ammonia. This is the average share of ammonia that is consumed globally for the production of urea. These starting points are therefore considered to represent an average sized ammonia plant combined with urea production.

In most existing literature, the conventional process based on natural gas reforming is compared to natural gas reforming with CCS or the scenario with 100% green hydrogen from electrolysis. However, it is also possible to substitute part of the reforming process with electrolysis, in order to use the CO<sub>2</sub> from methane reforming for subsequent urea production. Therefore, the following five ammonia/urea plant configurations have been considered and analysed in this study:

- Case 1A: Hydrogen production based on natural gas reforming, without CCS.
- Case 2A: Hydrogen production based on natural gas reforming, with CCS.
- Case 1B: Hybrid production of hydrogen based on natural gas reforming (55%) and water-electrolysis (45%), without CCS.
- Case 2B: Hybrid production of hydrogen based on natural gas reforming (40%) and water-electrolysis (60%), with CCU.
- Case 3: (100%) Electrolysis-based hydrogen production.

For each of these configurations, a mass balance was constructed using the data from the IEAGHG study as a starting point and scaling different material flows according to the requirements of each case. Table 4 provides an overview of the main material flows for each configuration.

#### 3.1.1 Standard configuration: case 1A

Figure 2 shows the BFD of this configuration. The plant produces hydrogen in a so called HyCO plant that uses natural gas as feedstock and as fuel. The total energy input of this plant is 486 MW (LHV). The plant is integrated to an ammonia synthesis loop with a nominal capacity of 1350 t/d. The plant, and all other configurations considered in this study also integrate an urea production unit with a capacity of almost 1240 t/d. But because this part is the same in all cases, and not crucial for the

analysis in this study which focusses primarily on the cost of ammonia, it is left out of this and other BDFs.

In this configuration, not all the CO<sub>2</sub> that is removed from the ammonia synthesis gas is used for urea production. The residual amount of CO<sub>2</sub> is sent to the stack and emitted to the atmosphere. In this case the residual CO<sub>2</sub> amounts to about 800 t/d. Total CO<sub>2</sub> emissions, including the CO<sub>2</sub> from the natural gas that is used as fuel, are more than 1480 t/d. In practice, the residual CO<sub>2</sub> can also be sold and supplied to external users for a variety of industrial (e.g. carbonated beverages), chemical and pharmaceutical (e.g. production of methanol, inorganic and organic carbonates, polyurethanes and sodium salicylate) and electronic applications (e.g. surface cleaning in circuit board assembly). In the IEAGHG-study all CO<sub>2</sub> is used for urea production, and no residual CO<sub>2</sub> is sent to the stack.

### 3.1.2 Standard configuration including CCS: case 2A

To reduce the CO<sub>2</sub> emissions from ammonia and urea production the plant can be equipped with a unit to capture the CO<sub>2</sub> from the flue gas of the reformer. This is a possibility for plants located in areas where underground storage options are available and storage is allowed. Figure 3 presents the BDF of this configuration. It is assumed that the residual CO<sub>2</sub> from the CO<sub>2</sub> removal unit is combined with the captured CO<sub>2</sub> from the flue gas, and is also sent to the storage. In this case the CO<sub>2</sub> emission is reduced to 78 t/d and 1403 t/d of CO<sub>2</sub> is sent to a storage.

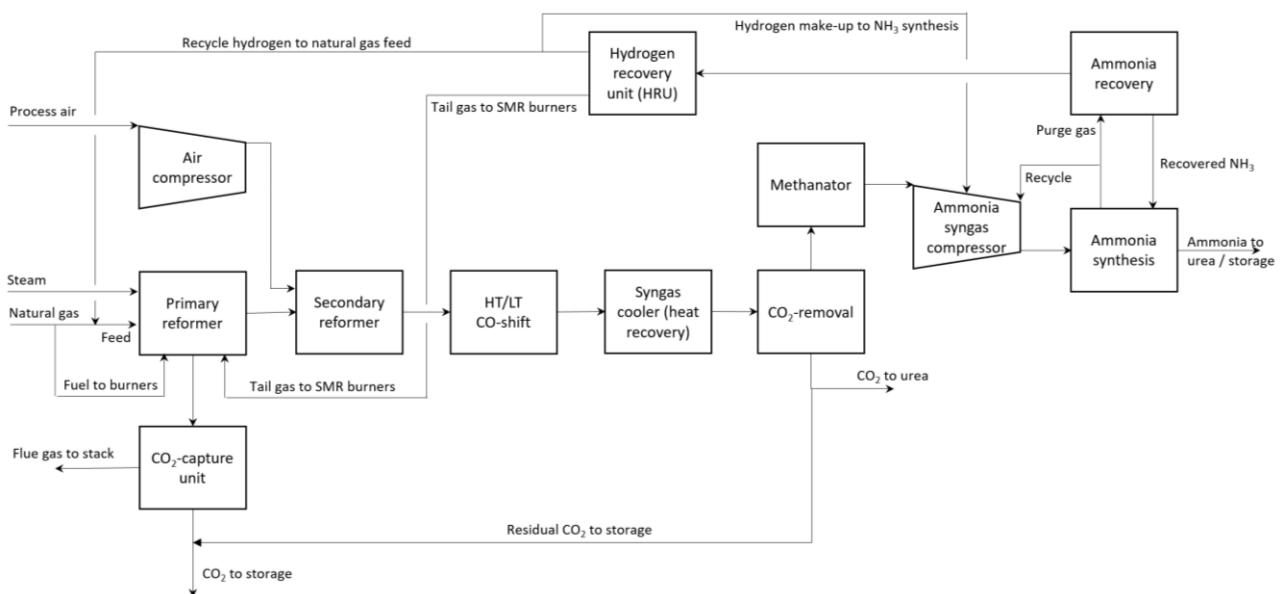


Figure 3: Simplified block flow diagram of a conventional ammonia plant with CCS.

### 3.1.3 Hybrid configuration without CCS: case 1B

This case combines natural gas reforming and water-electrolysis for the production of hydrogen. As only 52% of the ammonia is converted to urea, the capacity of the reformer can be decreased to a level that just enough CO<sub>2</sub> can be obtained from the CO<sub>2</sub> removal section for urea production. The capacity of the reformer can be reduced from 486 MW to 267 MW (LHV). The remaining CO<sub>2</sub> emission amounts to 403 t/d. The reduced hydrogen production from reforming is supplemented by

hydrogen produced through electrolysis, which supplies 45% of the H<sub>2</sub> demand of the plant. Assuming an electrolysis plant efficiency of 75% (HHV), an electrolyser with a capacity of 244 MW based on electricity input would be needed to produce a little over 110 t/d of hydrogen.

Figure 4 presents the BDF of this configuration. For the analysis in this study, the capacities of the primary and secondary reformer have been reduced proportionally. The mass balance analysis then showed a shortage of nitrogen for the ammonia synthesis because of the reduced amount of process air needed for reforming. The nitrogen is supplemented from an air separation unit. Because no data were found for an ASU of a quality comparable to the IEAGHG study, the effect of the additional need of nitrogen was approximated by using a market price for nitrogen and investigating the sensitivity to it.

The results in Table 4 show that the electrolysis plant also produces a large amount of oxygen (884 t/d). This oxygen could be used to replace the oxygen supplied via the process air. The air-blown secondary reformer would thus change into an oxygen-blown reformer. This will have an effect on the thermal management and the design of the integrated hydrogen/ammonia/urea plant. At the same time, with the replacement of air by oxygen, nitrogen will no longer be introduced via the reformer, so that all nitrogen for the ammonia synthesis then has to be supplied by an air separation unit. Perhaps these adjustments offer opportunities for optimization of the overall process. However, this study did not further investigate the possibilities and how they would work out.

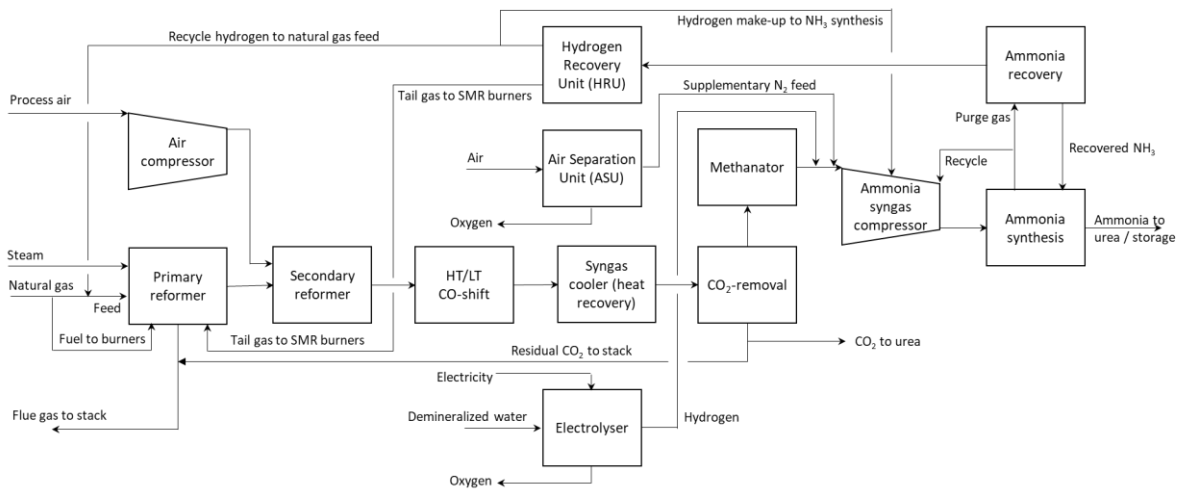


Figure 4: Simplified block flow diagram of an ammonia plant without CCS but with partial production of hydrogen through electrolysis.

### 1.1.1 Hybrid configuration with CCU: case 2B

If the CO<sub>2</sub> that is captured from the reformer flue gas is also utilized for urea production, the capacity of the reformer can be further reduced. The electrolyser supplies 60% of the required H<sub>2</sub> for ammonia synthesis. Figure 5 shows the BFD for this variant. In this case the direct emissions from ammonia production are minimized, while avoiding the need to store CO<sub>2</sub> or the need to supply CO<sub>2</sub> from an external source for the urea synthesis. The only direct emissions left, about 30 t/d, is the CO<sub>2</sub> that cannot be captured from the flue gas. On the other hand, because the capacity of the reformer section is further reduced, the need for supplementing nitrogen for the ammonia synthesis increases from 541 to 727 t/d. Also in this case no further study has been done into the possibilities and impact of replacing process air for reforming with oxygen that is formed during water electrolysis.

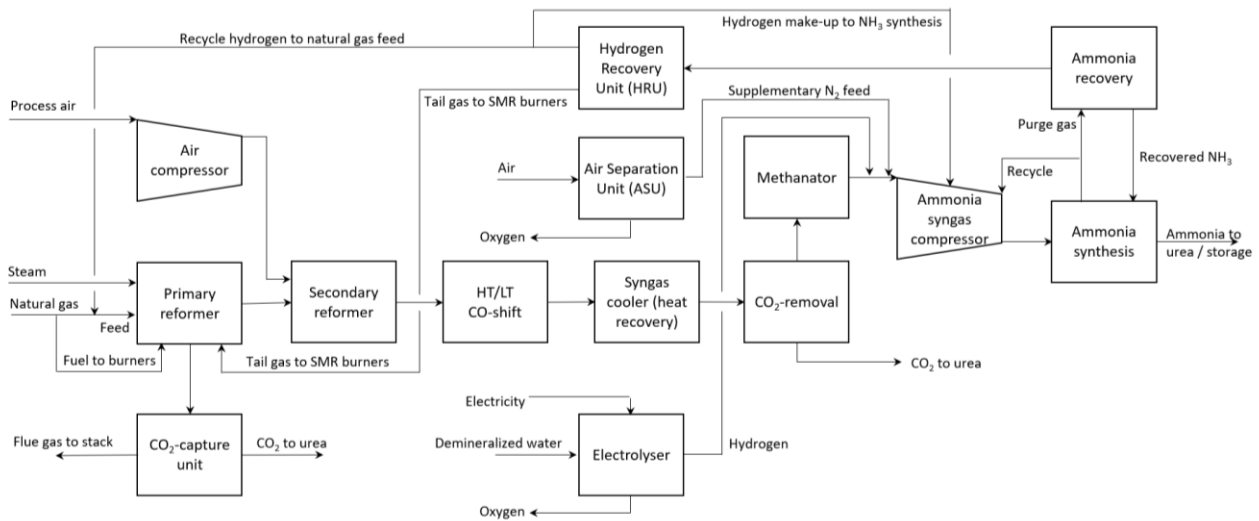


Figure 5: Simplified block flow diagram of an ammonia plant with CCU and partial production of hydrogen through electrolysis

### 1.1.1 Electrolysis based process: case 3

A final alternative is to replace the entire hydrogen production via reforming with electrolysis. Figure 6 presents the BFD of this variant. All nitrogen must now be obtained from an ASU. In this case, no CO<sub>2</sub> is formed during the production of hydrogen. There are therefore no direct emission of CO<sub>2</sub>. However, there is also no CO<sub>2</sub> available for the production of urea, so that when producing urea, the CO<sub>2</sub> must be supplied from another source, from outside the ammonia-urea plant.

Despite the lack of direct (scope 1) emissions, there may be indirect (scope 2) emissions due to the use of electricity generated elsewhere for electrolysis. Indirect emissions can also be introduced through the electricity consumption for the ASU to supply the nitrogen for the ammonia synthesis, or the energy used to supply the CO<sub>2</sub> for urea production. The indirect emissions are determined by the emission factor of the electricity/energy used. If only electricity is used that is generated using renewable energy sources such as solar energy, wind energy and hydropower, the emission factor is zero or negligibly low, and so are the indirect emissions.

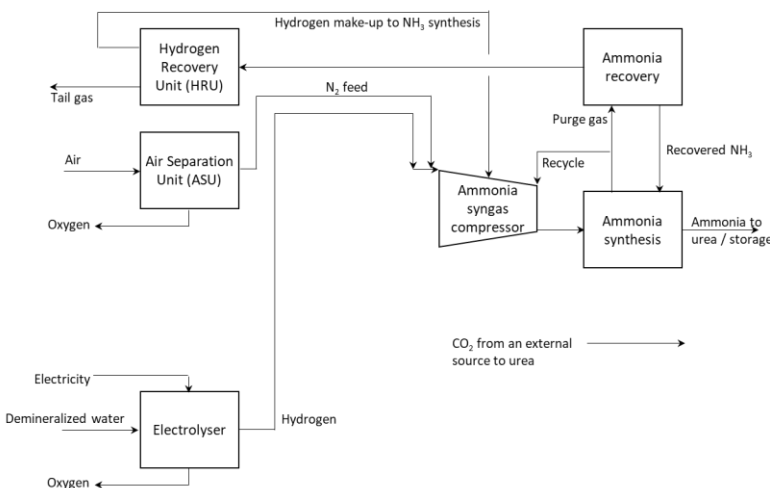


Figure 6: Simplified block flow diagram of an ammonia production plant based on hydrogen from electrolysis.

Table 4: Mass balances of process configurations.

Item/description	Unit	Case 1A: Standard w/o CCS	Case 1B: Hybrid w/o CCS	Case 2A: Standard with CCS	Case 2B: Hybrid with CCU	Case 3: Electrolysis
Reforming						
Natural gas feedstock	t/d	649	356	649	255	-
Natural gas fuel	t/d	255	140	255	100	-
Water (steam)	t/d	898	493	898	353	-
Oxygen (in process air)	t/d	369	202	369	145	-
Nitrogen (in process air)	t/d	1198	657	1198	471	-
Hydrogen production	t/d	247	136	247	97	-
Reformer total energy input	MW <sub>input</sub> (LHV)	486	267	486	191	-
Water-electrolysis						
Water (demineralized)	t/d	-	996	-	1341	2212
Electrolyser	MW <sub>input</sub>	-	244	-	328	541
Hydrogen production	t/d	-	111	-	150	247
Oxygen byproduct	t/d	-	884	-	1191	1964
Ammonia synthesis						
Hydrogen total input	t/d	247	247	247	247	247
Nitrogen total input	t/d	1215	1215	1215	1215	1215
Nitrogen (from ASU/external source)	t/d	-	541	-	727	1198
Ammonia total production	t/d	1350	1350	1350	1350	1350
Urea synthesis						
Ammonia input	t/d	702	702	702	702	702
Carbon dioxide input	t/d	908	908	908	908	908
Urea total production	t/d	1238	1238	1238	1238	1238
Carbon dioxide balance						
CO <sub>2</sub> from natural gas feedstock	t/d	1709	938	1709	672	-
CO <sub>2</sub> from fuel	t/d	681	373	681	267	-
Total CO <sub>2</sub> emissions	t/d	1481	403	78	31	-
CO <sub>2</sub> to storage	t/d	-	-	1403	-	-



## 3.2 Cost model

The total project costs for the different cases consist of investment costs (equipment, installation and commissioning etc), operational costs (O&M costs, network fees, CO<sub>2</sub> transport and storage) and cost of fuel and feedstock (natural gas, electricity, CO<sub>2</sub> ETS price, nitrogen). The following sections detail the assumptions used to estimate the costs for the different cases considered in this study.

### 3.2.1 Capital cost estimation

The IEA GHG study [9], which has been used as a starting point for this study, reports total project cost for the integrated ammonia and urea production plant. To be able to scale different parts of the plant, the integral investment costs have been disaggregated into separate costs for the hydrogen production plant, the ammonia synthesis loop and the urea plant. Two studies were used for this, which also report total project costs of comparable quality.

First, costs have been estimated for the urea-unit based on a study by Mitsui [10] which contains separate data on an integrated ammonia plant and a 3000 t/d urea-plant. Facility utilities are reported separately. Ratio-wise, utility costs have been allocated to the urea plant. Cost data were then adjusted for inflation and currency, and finally scaled according to the 0.6-scaling rule to the plant capacities used in the IEAGH study [9], i.e. 2260 and 2380 t/d respectively. The 0.6-scaling rule is a widely used engineering rule for scaling of cost estimates for thermochemical processes.

The resulting costs for the integrated ammonia plant have been further broken down using data from the H21 North of England study [11], which reports separate costs estimates for the hydrogen production part and the ammonia synthesis part of an integrated ammonia plant. For the production of the ammonia synthesis gas, this study has opted for an oxygen-blown ATR. The air separation unit (ASU) required for the oxygen at the same time produces the nitrogen required for the ammonia synthesis as a by-product. Thus, the ASU is extra compared to the air-blown reforming part in the IEAGHG study. In contrast, the oxygen-blown variant does not require a separate, relatively expensive CCS-unit to achieve a high CO<sub>2</sub> capture rate. It has therefore been assumed that the costs for the oxygen-blown ATR including ASU are comparable to the variant with a separate CCS unit for the capture of the fuel CO<sub>2</sub>, i.e. case 2A. The ratio of the cost estimates for the individual components from the North of England study [11] was used to further break down the cost estimate for the variant with CCS from the IEAGHG report [9]. An estimate for the reformer part for the variant without CCS (case 1A) is then obtained by deducting the costs associated with the CCS unit, as can be derived from the IEAGHG report [9].

After cost breakdown, investment costs were estimated for the reformer units in the hybrid process configurations with an electrolyser using the 0.6-scaling rule. As in the reference case of reforming with CCS (case 2A) only 52% of the feedstock CO<sub>2</sub> is used for urea production, more CO<sub>2</sub> needs to be compressed for storage compared to the case analysed in the IEAGHG study. The CO<sub>2</sub> compressor cost are sized accordingly using the 0.6-scaling rule. In case 2B, no costs for CO<sub>2</sub> compression are included because in this case the captured fuel CO<sub>2</sub> is used for the production of urea and there is therefore no storage of CO<sub>2</sub>. The investment costs of the reformer units with and without CCS in the different process configurations and the investment costs for the ammonia synthesis unit have been assumed constant in all years considered in this study.

The total CAPEX for the electrolysis part of the process consists of three cost components: the investment in the electrolyser system (excluding compression), the investment in the hydrogen compressor and the integration cost. Firstly, it is assumed that the electrolyser system CAPEX decreases over time as the technology matures. Since the capacity of the electrolysers is several hundred megawatts in all variants, the specific investment (EUR/kW) is assumed to be independent of the capacity of the electrolyser. Secondly, the compressor investment cost for hydrogen compression to 30 bar is assumed to only depend on electrolyser capacity and to remain constant in time. Cost data for the electrolyser system and compressor were obtained from Siemens. The compressor cost data was provided for an electrolysis unit of 20 MW and 100 MW. To obtain the compressor cost equivalent to the electrolyser capacities required for the scenarios in this study (1B, 2B and 3), the scaling factor was calculated from the two datapoints and extrapolated to the required electrolyser capacities, see Figure 1. Thirdly, the cost of integrating an electrolysis system with an ammonia synthesis process is estimated using data from the North of England report [11]. The total cost of the separate hydrogen and ammonia plant is subtracted from the total cost of the integrated plant, which leaves the integration cost. This value is scaled using the capacity of ammonia production and the 0.6-scaling rule. Lastly, the sum of electrolyser and compressor cost is multiplied with a factor of 1,8 to convert the bare equipment cost to total project costs, and the integration cost have been added (which already contain the 1.8 factor) to arrive at total cost.

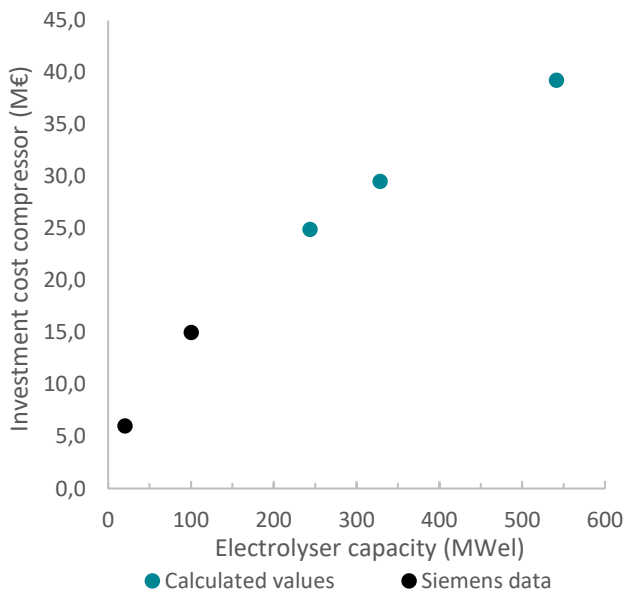


Figure 7: Investment cost for mechanical hydrogen compression for different electrolyser capacities.

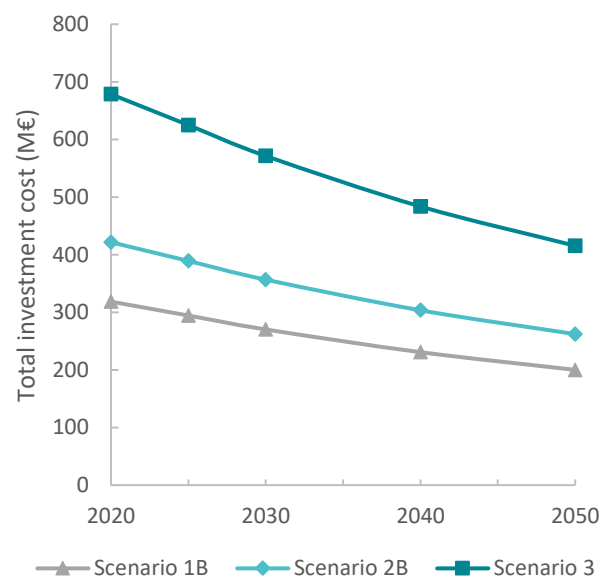


Figure 8: Total investment cost for hydrogen production from electrolysis, including compression multiplied by a project cost factor of 1,8.

### 3.2.2 Operational cost estimation

The operational costs are determined for each process steps relevant for the different plant configurations: reforming, ammonia synthesis, electrolysis, H<sub>2</sub> compression and CO<sub>2</sub> transport and storage.

- The operational costs of reforming and ammonia synthesis are derived from the total fixed and variable cost (excl. fuel and feedstock cost) of an integrated ammonia plant, as reported by the IEA GHG study [9], with scaling of the costs for the reformer part according to the capacity of the reformer in the different process variants.
- The operational costs related to electrolysis are calculated based on a linear decrease of specific operational cost of 30 €/kW/y for electrolyzers installed in 2020 to 21 €/kW/y for units installed in 2050 as indicated by Siemens for this project.
- For the H<sub>2</sub> compression step, the operational costs are estimated to be 4% of the investment cost of the compressor.
- CO<sub>2</sub> transport and storage costs have been assumed constant at 20 €/ton in the reference scenario and total costs are calculated by multiplying this value with the amount of CO<sub>2</sub> stored in each case.

The other operational costs that were taken into account are:

- The stack replacement is modelled as an operational cost. The cost of stack replacement was taken from the data provided by Siemens. The stack replacement cost is approximately 50% of the total electrolysis system cost (excl. compression). During the 25 year technical lifetime of the entire plant, the electrolyser stack must be replaced once.
- Network tariffs for natural gas apply to all process variants. The fees from the DSO Liander were used [12]:
  - a variable fee of €1.84/month/(Nm<sup>3</sup>/h)<sub>max</sub>
  - a fixed transport fee of €71.25 /month
  - a fixed connection fee of €76.73 /month
- Network tariffs for electricity apply to the plant configurations which include electrolysis. An average fee of €50.4/kW<sub>e</sub>/year is assumed, based on the weighted average of the network fees from the regional and national network operators in the Netherlands in 2020 [13].

### 3.2.3 Fuel, feedstock and emission cost

The IEA's World Energy Outlook 2020 [14] was used for the natural gas and CO<sub>2</sub> price inputs for the model. The natural gas price is assumed to develop according to the Stated Policy Scenario (STEPS). The data between 2019, 2025, 2030 and 2040 is interpolated linearly. Between 2040 and 2050, the gas price is assumed to remain constant. For the carbon price, the values were taken from the Sustainable Development Scenario (SDS) for advanced economies, because these values are more in line with current EU-ETS price development trends than the reported values from the STEPS. The data is interpolated between the datapoints for 2025 and 2040, and extrapolated following the same linear trend after 2050.

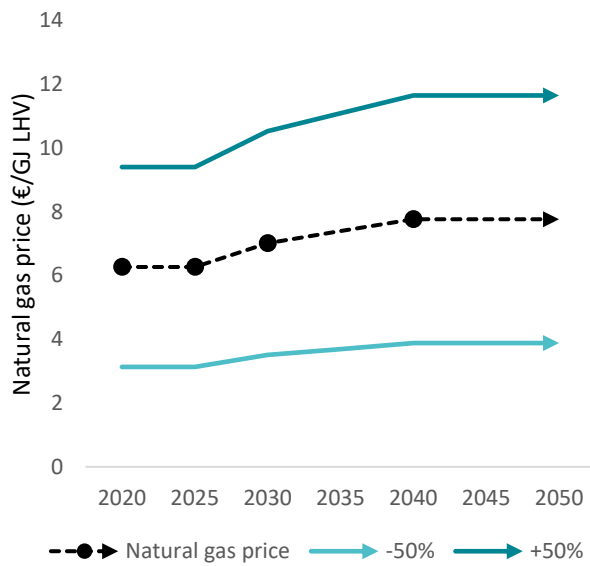


Figure 9: Development of the natural gas price from 2020 until 2050, including the price scenarios used for sensitivity analysis (-50% and +50%).

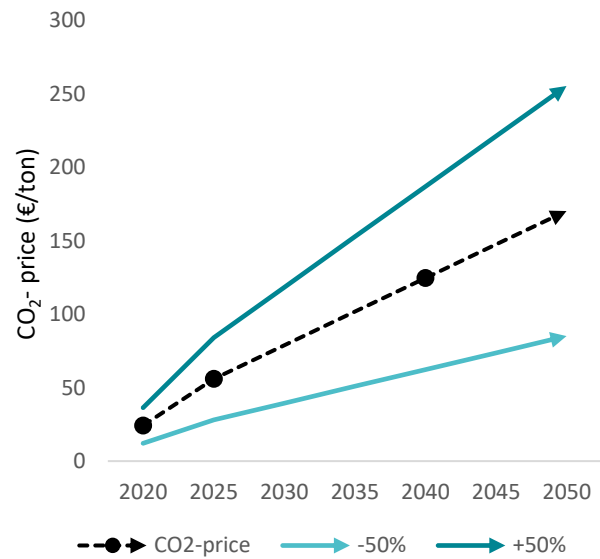


Figure 10: Development of the CO<sub>2</sub> price under the EU ETS from 2020 until 2050 and the price scenarios used for sensitivity analysis (-50% and +50% of the base case).

In the scenarios 1B, 2B and 3, there is a need for nitrogen from an external source, because the reforming unit does not produce sufficient N<sub>2</sub> to supply the ammonia synthesis unit. It was difficult to find investment cost data of an air separation unit of the correct capacity and of comparable quality to the other investment costs. Instead, statistical data of recent years on trade volumes and trade value of industrial gases has been used to determine a proxy for the cost of nitrogen [15]. The reference scenario assumes constant cost of 32 €/tonne nitrogen.

## 4 Results and discussion

This chapter discusses the results of the techno-economic analysis, which were calculated using the methodology described in the previous chapter. First of all, the break-even electricity price is calculated by comparing the electrolysis-based plant configurations with the base case of natural gas reforming with or without CCS. Additionally, the effect of the cost assumptions is analysed by performing a sensitivity analysis on multiple parameters. Secondly, the requirement of renewable electricity to power the different cases is determined per country, as well as on an overall EU28 level. Thirdly, the potential for emissions reduction is discussed for each scenario.

### 4.1 Break-even electricity price

In the cost analysis, assumptions were made for all parameters except for the costs of electricity; the electricity costs are the big unknown. In order to determine under which conditions electrolysis-based ammonia production can be a competitive alternative to the conventional process based on natural gas reforming, the break-even electricity price was calculated. This is the value for which the levelised cost of ammonia (LCOA) using hydrogen from electrolysis is equal to the LCOA using hydrogen of the steam reforming process. The LCOA is calculated as the ratio of the discounted total costs of the plant divided by the discounted sum of ammonia produced during its lifetime (25 years). The total costs are the sum of the annualised investment costs in the process plant (10 year depreciation with WACC of 6%), the operation and maintenance costs, the natural gas costs, nitrogen cost, CO<sub>2</sub> emission allowance cost, electricity and CO<sub>2</sub> transport and storage costs. In general, the higher the break-even electricity price, the more competitive a process variant with electrolysis is compared to a reference without electrolysis. Additionally, if the break-even electricity price for electrolysis-based ammonia production approaches the levelized cost of electricity production from renewable sources, these cases can become a realistic alternative to conventional ammonia production.

The hybrid cases (1B and 2B) and the 100% electrolysis case (3) are compared to the reforming cases without CO<sub>2</sub> capture (1A) and with CO<sub>2</sub> capture (2A). The results are shown in Figure 11. It is important to note that the years plotted on the x-axis signify the first year of a project with a lifetime of 25 years. The break-even electricity price indicated for a specific year (dots in the figure) represent the average electricity price over the lifetime (25 years) of a production facility installed in that particular year. Figure 11 clearly shows that the break-even electricity price increases with time in all cases. The reason for this is that natural gas prices and CO<sub>2</sub> taxes are expected to increase, while simultaneously the capital costs associated with electrolysis are expected to decrease.

The black curves in the figure show the break-even electricity price for the different electrolysis cases, compared to the reference case of reforming without CO<sub>2</sub> capture. The hybrid case without CO<sub>2</sub> capture (1B) has the highest break-even electricity price. Additional reduction in CO<sub>2</sub> cost due to capture and use for urea production does not outweigh the cost of additional CO<sub>2</sub> capture and a somewhat larger electrolysis plant. Completely replacing hydrogen production from reforming by electrolysis further reduces the break-even electricity price. This indicates that that under the assumption of the reference price scenarios electrolysis is still more costly than reforming and that overall emitting some CO<sub>2</sub> still results in lower cost than not emitting CO<sub>2</sub> at all.

The break-even electricity prices for the cases compared to reforming with CO<sub>2</sub> capture (the orange curves in Figure 11) are lower than the break-even electricity prices compared to reforming without

CO<sub>2</sub> capture (the black curves). The costs of CO<sub>2</sub> capture and storage are offset by the avoided rising CO<sub>2</sub> taxes in the future, resulting in a lower combined cost for the reference with CCS (case 2A) compared to the reference without CCS (case 1A). Therefore, there is less ‘room’ for the electricity costs related to electrolysis.

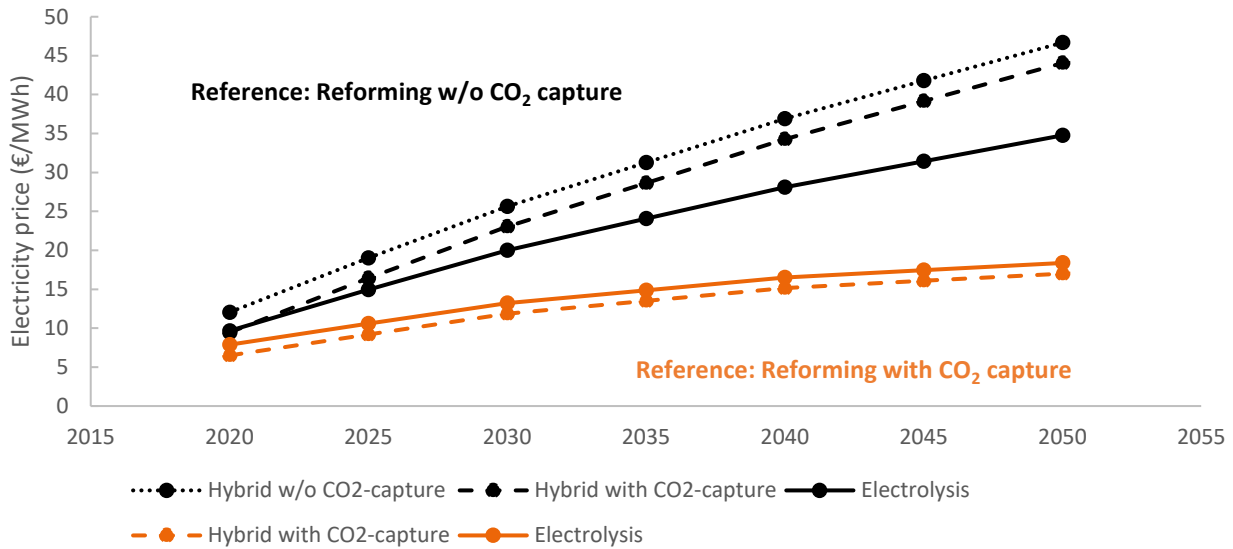


Figure 11: Break-even electricity price for the different electrolysis cases, compared to the reference cases of reforming with and without CO<sub>2</sub> capture.

#### 4.1.1 Levelised cost of electricity comparison

The levelised cost of electricity (LCOE) can be used to estimate the price of electricity for different renewable energy sources. Figure 12 shows the global weighted average LCOE from utility-scale renewable power generation over the last decade, published by IRENA [16]. Converting the values to euro’s yields an average LCOE of €50/MWh for solar PV, €74/MWh for offshore wind and €34/MWh for onshore wind in 2020. In optimal locations, the costs can be even lower. The figure shows that the cost for solar and wind power generation have been decreasing at a significant rate from 2010 to 2020. These learning curve trends can be extrapolated towards the near-term (3-5 years), although it is not expected that cost reductions will be achieved at the same rate in the long term [16]. Nevertheless, it is likely that the LCOE of solar and wind will decline further in the future.

A comparison of the break-even electricity prices in Figure 11 with the costs of solar and wind power generation in Figure 12 shows that the costs in the short term are still above the break-even prices in all cases. However, with a continued decrease in costs, and when compared with the reference case without CO<sub>2</sub> capture and storage, it is expected that in the course of the period between 2030 and 2040 the renewable electricity costs will reach a level comparable to the required break-even electricity price for a competitive transition to renewable hydrogen. At locations with optimal sun and wind conditions, this can be the case even earlier.

If CCS is possible and allowed and a switch to the fossil-based low-carbon hydrogen option is made first in view of rising CO<sub>2</sub> prices, then a switch to renewable hydrogen at a later stage seems more challenging. The break-even electricity prices when compared to a reference case with CCS are at a much lower level. The reason is that the reference system with CCS experiences little or no effect from CO<sub>2</sub> prices that are higher than the costs for CCS.

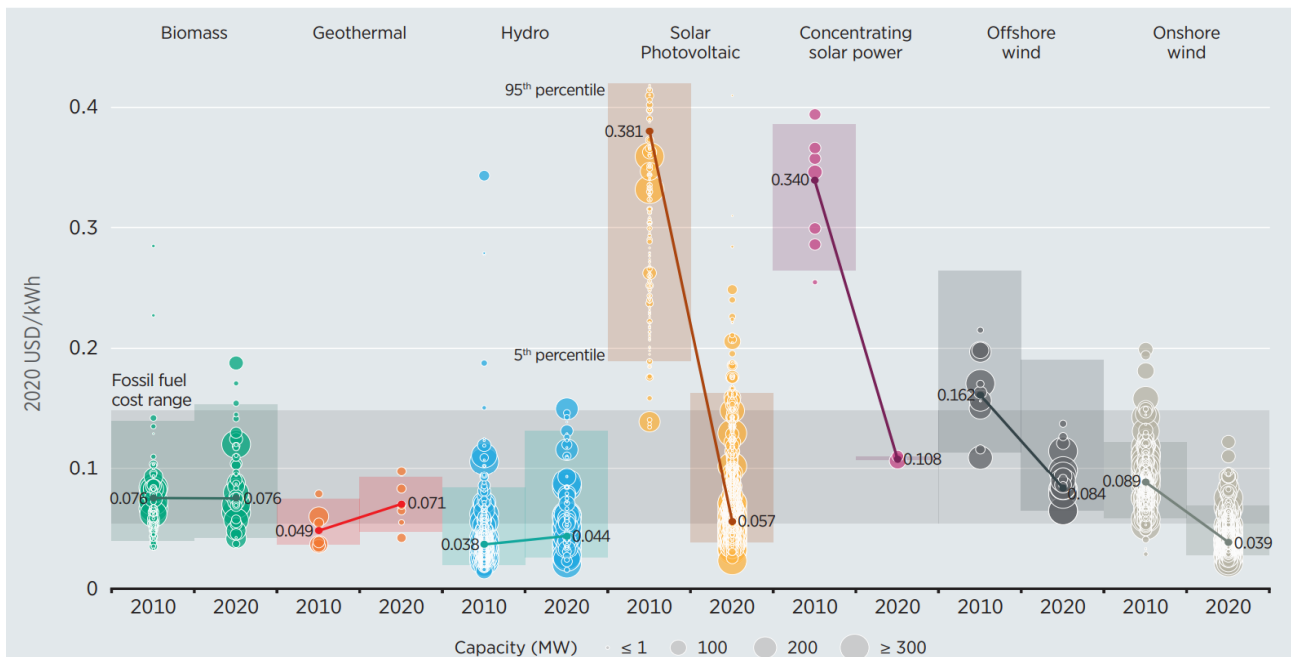


Figure 12: Global LCOEs from newly commissioned, utility-scale renewable power generation technologies, 2010-2020 [16].

#### 4.1.2 Sensitivity analysis

The effect of key assumptions on the break-even electricity price is evaluated by performing a sensitivity analysis for different input parameters.

The natural gas price is shown to have a large impact on the break-even electricity price for all plant configurations. To illustrate, the effect is shown in Figure 13 and Figure 14 for the case of 100% electrolysis (case 3). If the natural gas price decreases by 50% (see Figure 9, natural gas prices ranging from 3-4 €/GJ or 11-14 €/MWh), this results in lower break-even electricity prices, and the reference cases becomes more difficult to beat. In 2020, it even becomes negative, because the overall costs of electrolysis (excl. the electricity cost) are higher than the overall cost of the natural gas reforming cases (incl. natural gas). However, if the natural gas price would increase by 50% (natural gas prices ranging from 9-12 €/GJ or 34-42 €/MWh), the opposite effect is visible. A switch to electrolysis-based renewable hydrogen becomes much more attractive, even when compared to the CCS option (Figure 14), especially in combination with expected decrease in investment cost of electrolysis in the 2030-2050 timeframe.

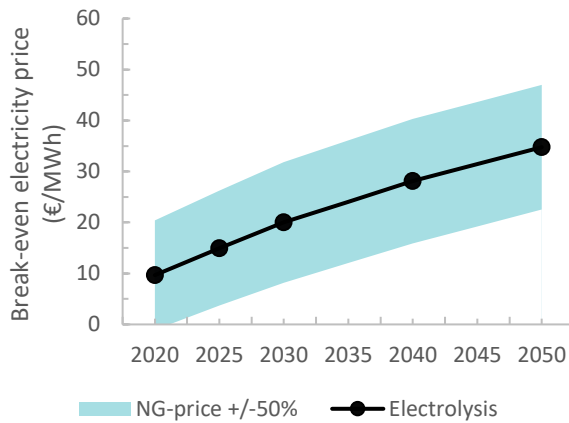


Figure 13: Sensitivity of the break-even electricity price to the natural gas price for case 3 compared to case 1A.

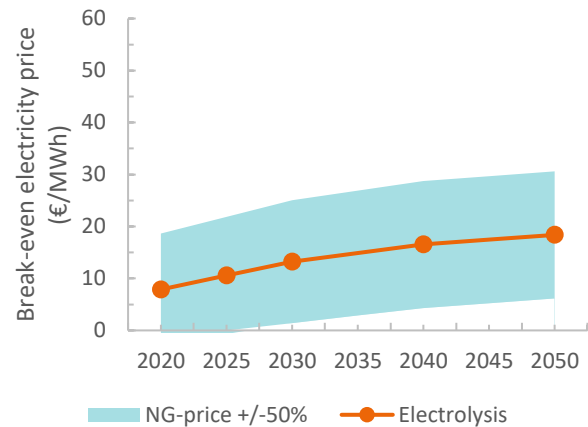


Figure 14: Sensitivity of the break-even electricity price to the natural gas price for case 3 compared to case 2A.

Similarly, decreasing or increasing the CO<sub>2</sub> price by 50% compared to the reference scenario (in which the CO<sub>2</sub> price increases from 24 €/tonne in 2020 to 125 €/tonne in 2040 and further to 310 €/tonne in 2080; Figure 10) has a significant effect on the break-even electricity price for all plant configurations compared to the reference plant without CO<sub>2</sub> capture (see Figure 15). At the higher CO<sub>2</sub>-prices, break-even electricity prices are found to be in the range of 34 - 52 €/MWh for the hybrid configurations in the period 2030 - 2040, and even increase to values well above 60 €/MWh towards 2050. Comparable values for the full electrolysis variant range from 27 €/MWh in 2030 to 47 €/MWh in 2050. A combination of higher CO<sub>2</sub> prices with higher gas prices will of course lead to even higher values for the break-even electricity prices.

However, the effect of the CO<sub>2</sub> price is negligible if compared to the reference case with CO<sub>2</sub> capture (case 2A), as shown in Figure 16. This is because the CO<sub>2</sub> price hardly affects the business case for case 2A, as only a very small amount of CO<sub>2</sub> is released to the atmosphere. This result implies that the CO<sub>2</sub>-price mechanism provides no incentive for the deployment of green hydrogen in ammonia production if existing ammonia production plants are already equipped with CCS. Other incentives are then needed for transitioning all fossil hydrogen based ammonia production to production with renewable hydrogen.



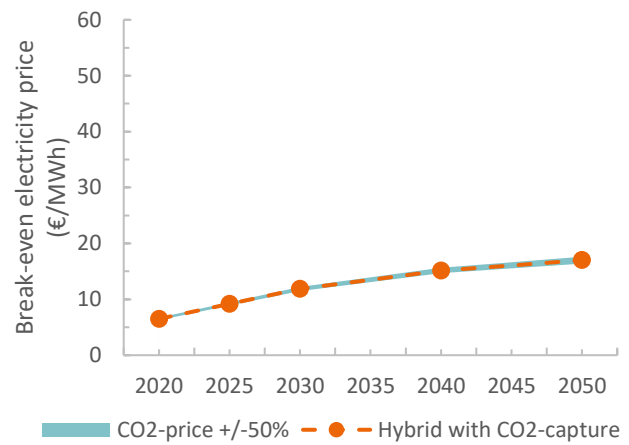
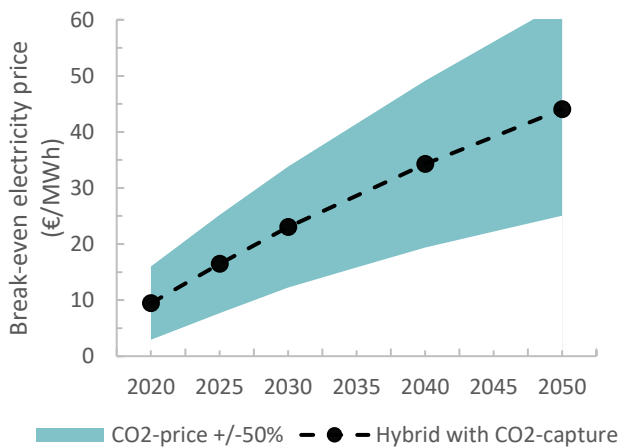


Figure 15: Sensitivity of the break-even electricity price to the CO<sub>2</sub> price for case 2B compared to case 1A.

Figure 16: Sensitivity of the break-even electricity price to the CO<sub>2</sub> price for case 2B compared to case 2A.

The electrolyser CAPEX has a moderate effect on the break-even electricity price, compared to both reference cases (see Figure 19 and Figure 20). The sensitivity bandwidth becomes narrower with time, because the electrolyser CAPEX decreases over time and consequently has a smaller impact on the resulting break-even electricity price.

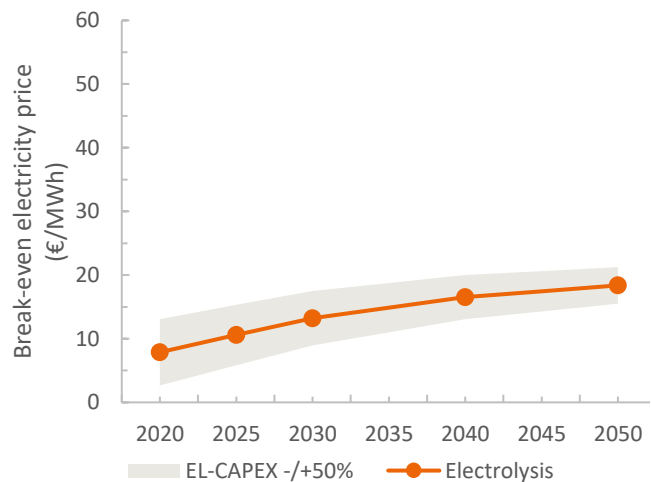
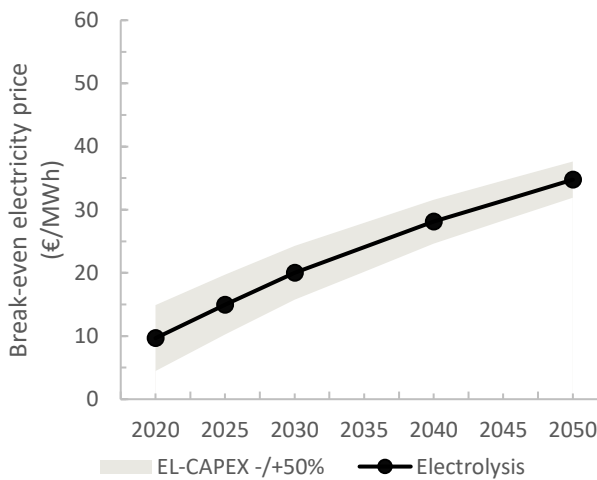


Figure 17: Sensitivity of the break-even electricity price to the electrolyser CAPEX for case 3 compared to case 1A.

Figure 18: Sensitivity of the break-even electricity price to the electrolyser CAPEX for case 3 compared to case 2A.

For the cost calculation of the different plant configurations, it is assumed that the utilization factor of the ammonia production facility is 90% in all cases. However, it is debatable whether this value is realistic, considering the assumption that zero-emission electricity is used for electrolysis. It is possible that the electrolysis can only be operated for a reduced amount of full load hours (lower utilization factor). This means that the capacity of the electrolyser must be increased in order to produce the same amount of hydrogen. Therefore, the effect of decreasing the utilization factor from 90% to 75% and to 60% is calculated and shown in Figure 19 and Figure 20. It is clear that a decrease in plant capacity utilization has a significant negative impact on the break-even electricity price. Because there is currently insufficient renewable electricity available, electrolysers cannot yet be operated continuously on a large scale to prevent an increase in fossil-based electricity production

and thus a counterproductive increase in CO<sub>2</sub> emissions. As the electricity system becomes increasingly sustainable and decarbonised, this effect will become less and less important and the number of full load hours for electrolysis may increase over time.

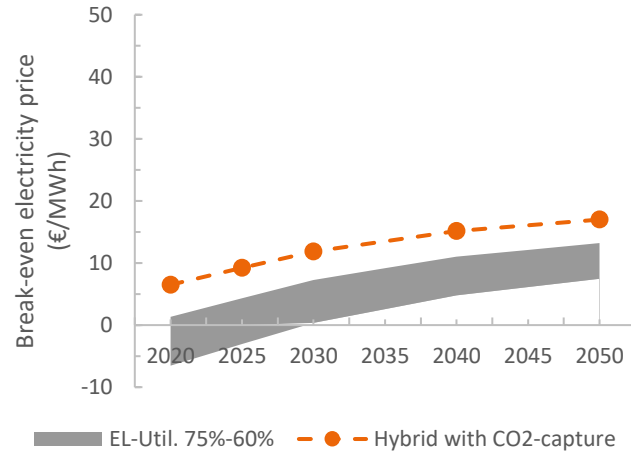
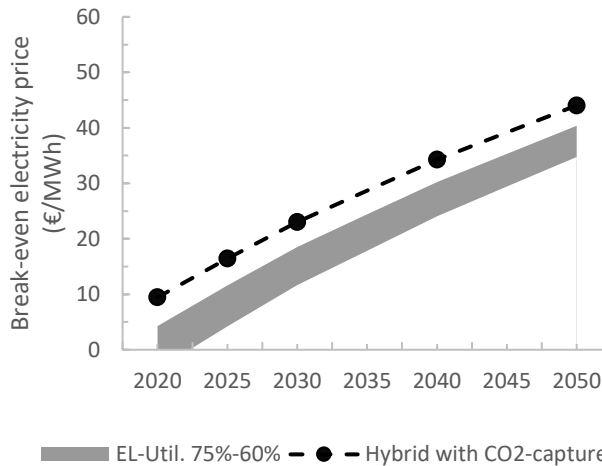


Figure 19: Sensitivity of the break-even electricity price to the utilisation factor for case 2B compared to case 1A.

Figure 20: Sensitivity of the break-even electricity price to the utilisation factor for case 2B compared to case 2A.

Of other parameters that have been studied, especially lower electricity network tariffs appear to have a significant positive effect on the break-even electricity price. A full exemption leads to an increase in the break-even price of more than 5 €/MWh compared to the value of the reference scenario (50.4 €/kWh/y). A plus or minus 50% variation of other parameters such as the WACC, the nitrogen price and the costs for CO<sub>2</sub> storage have a more limited effect of only one or a few €/MWh.

## 4.2 Renewable electricity requirement

Converting existing ammonia production capacity from natural gas reforming to electrolysis requires an increased amount of near-zero-emission electricity, in order to lead to a reduction in CO<sub>2</sub> emissions. Therefore, it is important to understand how the electricity demand for electrification of ammonia production relates to the amount of near-zero emission electricity in each country.

For this analysis, the volume of electricity that would be required for electrolysis in the EU28 member states which produce ammonia is calculated first. This is compared to the final electricity consumption in each country. Consequently, the required electricity is compared to the current and projected renewable electricity production volumes over the period 2025-2040.

### 4.2.1 Electricity demand for NH<sub>3</sub> production per country

The volume of electricity that would be required for electrolysis in the EU28 member states which produce ammonia (see Table 3) is calculated by scaling the amount of electricity required for electrolysis and H<sub>2</sub> compression for case 1B, 2B and 3, using the NH<sub>3</sub> production capacity in each country. The underlying assumption is that all the production plants in the EU are currently based on steam reforming of natural gas. The result is shown in Figure 21. The three cases shown represent 45%, 60% and 100% replacement of fossil-based hydrogen by electrolysis-based hydrogen using renewable electricity.

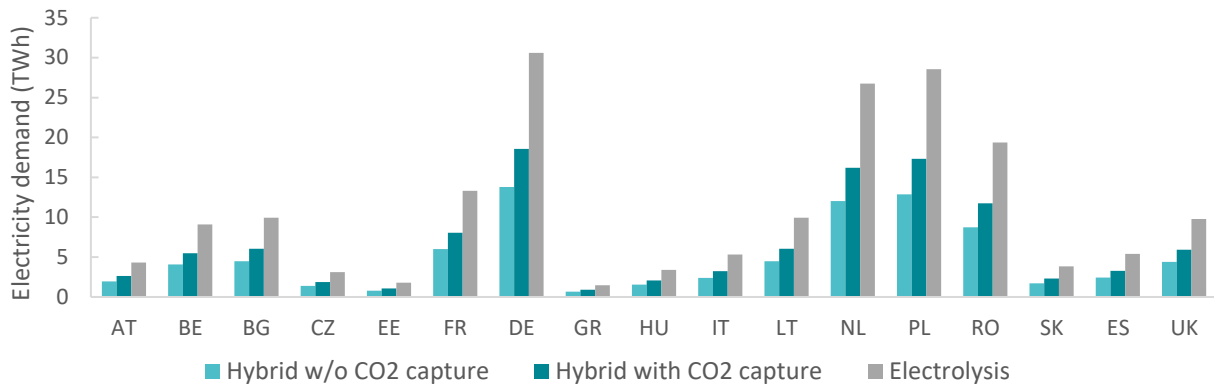


Figure 21: Electricity demand per country for the production of NH<sub>3</sub> in that country for the different electrolysis cases (1B, 2B and 3)

Additionally, the electricity demand necessary for ammonia production in the different cases is compared to the final electricity consumption in each country [Eurostat, final consumption 2018]. Figure 22 shows that a switch of the ammonia industry to renewable hydrogen from electrolysis would place a fairly large burden on electricity production, or requires a significant expansion of electricity production. Lithuania in particular stands out. In most countries this is due to a relatively low electricity consumption due to a small population size, a still limited consumption per capita or a combination of these. The Netherlands and Poland are an exception to this. In these countries the relatively large share is mainly due to the large size of the industry, which is illustrated by Figure 21.

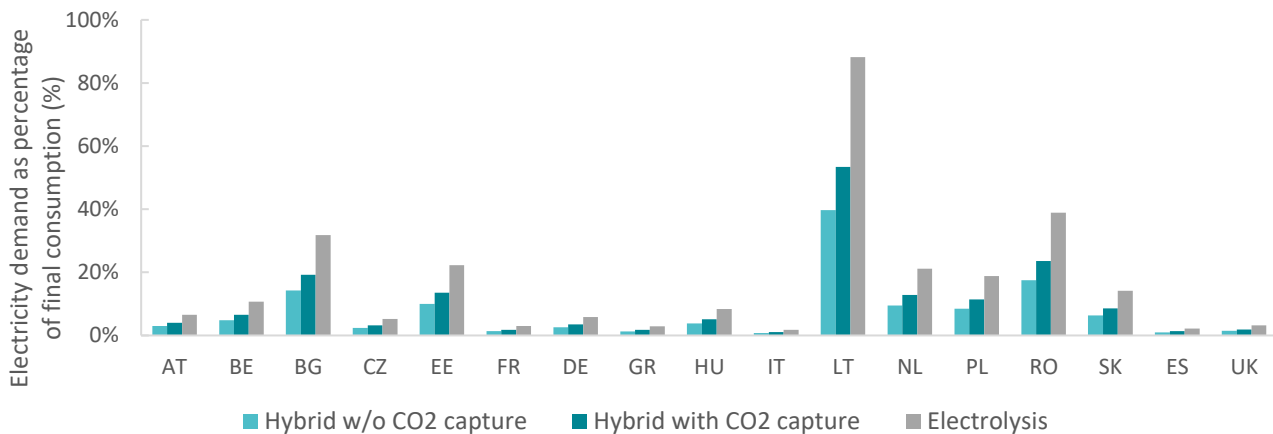


Figure 22: Electricity demand for NH<sub>3</sub> production per case (1B, 2B and 3) per country, expressed as a percentage of the national final electricity consumption.

#### 4.2.2 Comparison to current renewable energy production

In the following analysis, the electricity requirement for the different electrolysis plant configurations is compared to the projections of *renewable* electricity production per country. In practice, the electrolysis process could not only be powered by renewable sources such as solar PV or on- or off-shore wind, but also by nuclear power, biomass or fossil fuels with CCS. For this analysis, only solar PV and wind power were taken into account because these sources are expected to be very important for the energy supply of the future.

For the sake of comparison, the electricity demand is shown as a percentage of the national renewable energy production in 2018 in Figure 23. The renewable energy production volumes (in TWh) and capacities (in MW) from solar PV and wind in 2018 for all EU28 countries are taken from the Eurostat database [17] [18]. Since this database does not differentiate between on- and offshore wind, the values for onshore wind were calculated by subtracting the offshore wind data from ENTSO-E [19] from the total wind data from Eurostat.

Figure 23 illustrates the huge need and challenge for expanding renewable electricity production. Even in the case of a partial switch of the ammonia industry more than half of the countries would already require more electricity for their national ammonia production than the current combined generation of solar PV and wind. Notably, Lithuania, Slovakia and Bulgaria require significantly more electricity than they currently generate from solar PV and wind.

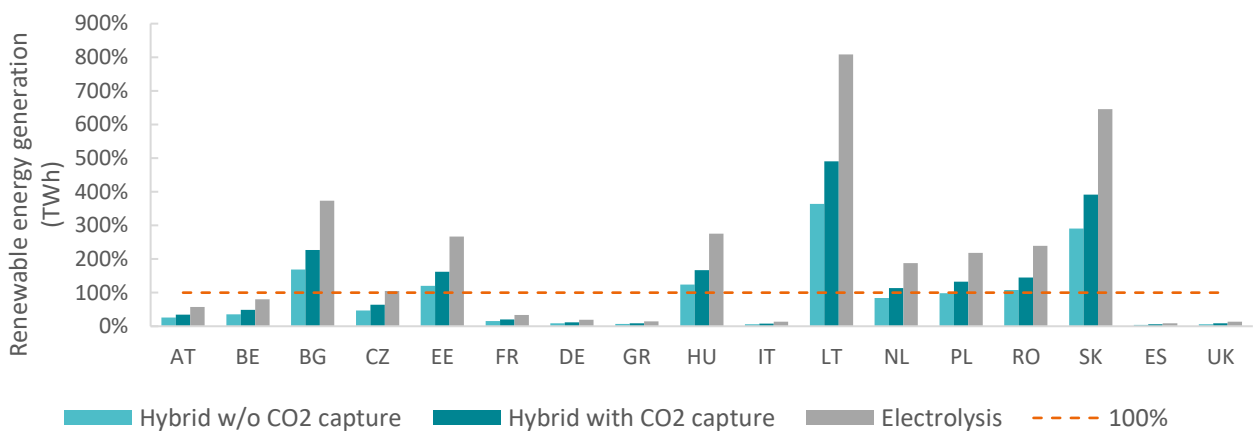


Figure 23: Electricity demand for NH<sub>3</sub> production per case (1B, 2B and 3) per country, expressed as percentage of renewable energy production (solar PV and wind) in 2018.

### 4.2.3 Comparison to projected renewable energy production (2025-2040)

Although the current renewable electricity production does not cover the required electricity demand for switching the ammonia production capacity to electrolysis in many countries, the installed capacities of solar PV and wind are expected to increase substantially in the future. Therefore, the projected renewable energy production for the period of 2025-2040 for all EU28 member states are compared to the electricity demand of NH<sub>3</sub> production. The solar PV and wind capacity projections for each EU28 member state are taken from the National Trends Scenario developed by ENTSO-E and ENTSG [20]. The total volume of renewable electricity generation is shown in Figure 24.

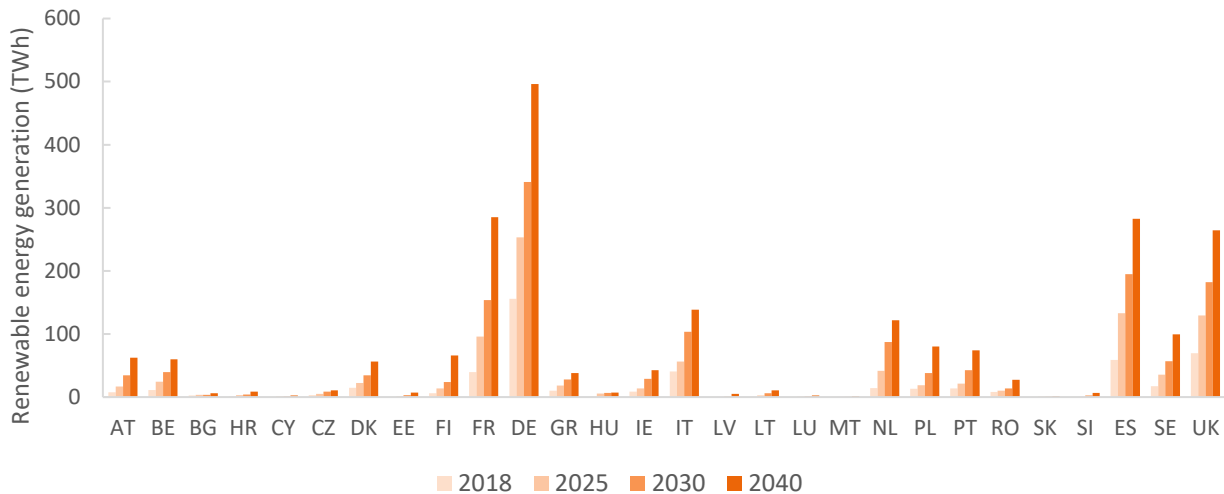


Figure 24: Renewable electricity production (solar PV and wind) projections for the EU28 member states, data for 2018 from Eurostat [17] [18] and projections for 2025-2040 from ENTSO-E [20].

If the renewable energy generation capacity increases according to the projections towards 2040 [20], and the ammonia production capacity remains constant at today's level, the relative share of electricity for renewable ammonia production decreases below the 100% line for most countries, as shown in Figure 25. However, as many other industries and other sectors also need to be supplied with renewable electricity, the demand due to electrification of ammonia production still represents a significant share. Further expansion of renewable electricity supply is clearly needed in many of the countries to arrive at a fully sustainable zero-emission electricity system.

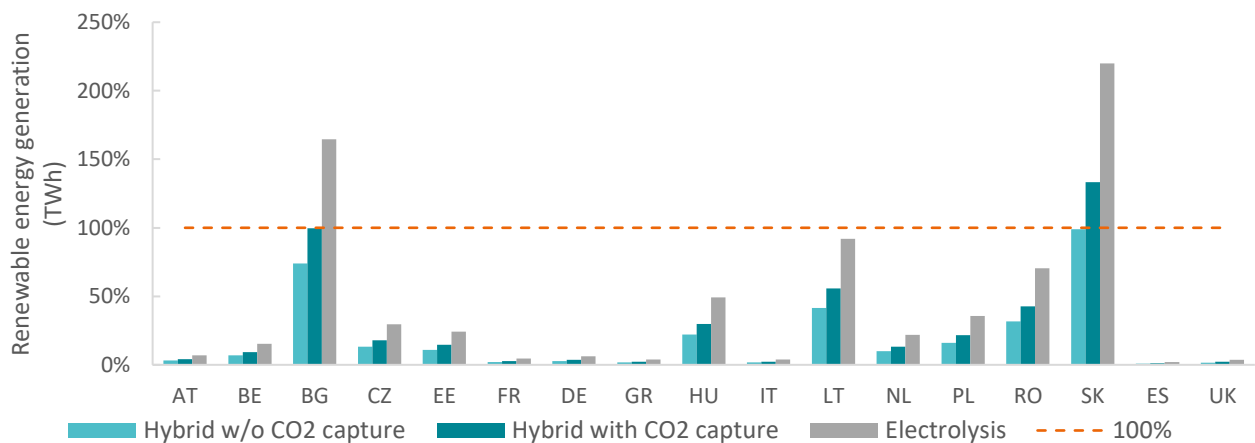


Figure 25: Electricity demand for NH<sub>3</sub> production per case (1B, 2B and 3) per country as percentage of renewable energy production in 2040.

So far, the analysis has only looked at the ratio of electricity generation and demand within country borders. Of course it is also possible to trade electricity between different EU28 member states. Therefore, it is interesting to look at the proportion of the electricity demand for NH<sub>3</sub> production and renewable electricity generation on an EU-level. Figure 26 presents the cumulative electricity demand of the three different process configurations on a time axis which can be considered as an arbitrary roll-out scenario. The transition will take place gradually because the conditions under which this must take place are not equally favourable everywhere. The three cases represent a 45% (“lowest hanging fruit”), a 60% (“can be done with some extra stimulation”) and a 100% (“most difficult part”) switch to renewable hydrogen. As shown in Figure 26, the cumulative electricity

generation from solar PV and wind in 2018 already exceeds the demand resulting from replacing 45% of current hydrogen use for ammonia production in the EU by renewable hydrogen from electrolysis. The difference becomes larger with increasing development of renewable capacity towards 2040. Still, considering that there are many other sources of renewable electricity demand in industry and other sectors, the electrification of ammonia production represents a substantial share. Final electricity consumption in the EU in 2018 (including the UK) already amounted to about 2900 TWh. A parallel H2FUTURE study on the steel industry has indicated that a switch to the hydrogen based Direct Reduction Process (DRI) may require another 340 TWh [21]. Apart from this there will be additional demand from other major electrification options such as electrical boilers in the industry, electric vehicles and residential heat pumps, clearly indicating an even greater need for zero-emission electricity production from solar, wind and other sources.

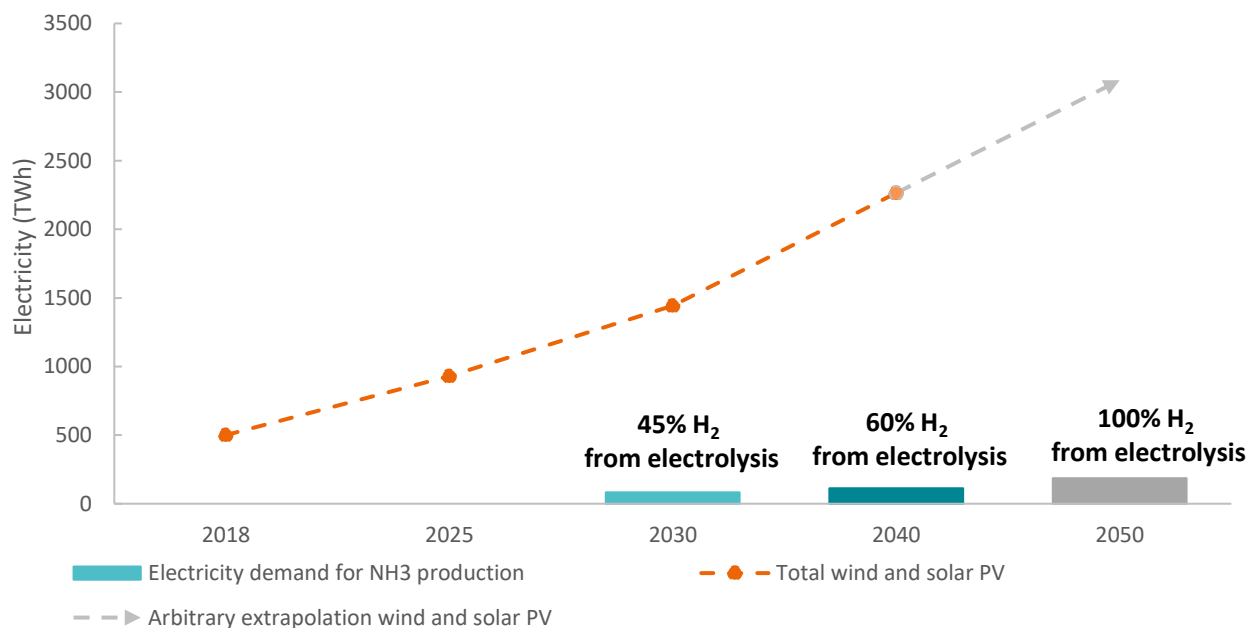


Figure 26: Cumulative electricity demand for NH<sub>3</sub> production within the EU28 for the different electrolysis scenarios (1B, 2 and 3), compared to cumulative electricity generation from solar PV and wind in the EU28.

One can try to solve the electricity balance on a country level or an EU level. However, regional constraints such as electricity infrastructure and land-use can pose a challenge for the production of green hydrogen in Europe. It is possible that future hydrogen demand will be met by importing it, rather than producing it locally [22]. Moreover, ammonia production capacity could be relocated to countries with less constraints on renewable (or low-carbon) electricity production and infrastructure. An example project is the development of a 2 GW electrolysis plant for Neom, in Saudi Arabia, by Air Products, thyssenkrupp, NEOM and ACWA Power. The large volumes of green hydrogen will be synthesized into ammonia for export to global markets [23].

### 4.3 Emission reduction potential

The different plant configurations discussed in Chapter 3 represent alternative pathways for emission reduction for the ammonia industry. Changing the hydrogen production technology from steam methane reforming to electrolysis could drastically reduce emissions if a zero-emission source of electricity is used. The direct emissions that originate from the steam reforming process were

calculated for the scenario that all ammonia production capacity in the EU28 were converted to one of the plant configurations. The results are shown in the dark blue bars in Figure 27.

However, since it was assumed that 52% of the produced ammonia is used for urea synthesis, it is important to also take into account the indirect emissions that result from the use phase of urea in the agricultural sector. Urea contains carbon ( $\text{CO}(\text{NH}_2)_2$ ), which is released during hydrolysis when it is applied to soil [1]. In each process configuration analysed in this study, 908 t/d  $\text{CO}_2$  is needed to synthesize urea in a plant which produces 1350 t/d  $\text{NH}_3$  (see Section 3.1). This  $\text{CO}_2$  is only temporarily sequestered in the form of urea and rereleased downstream. Using these values, the amount of  $\text{CO}_2$  resulting from urea use in the EU28 is calculated, shown in the light blue bars in Figure 27.

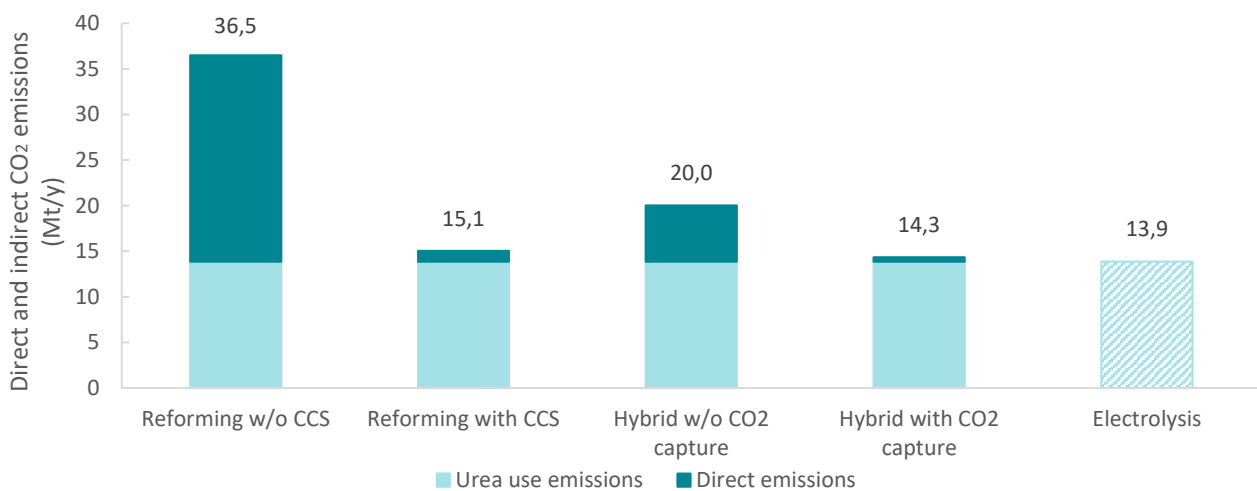


Figure 27: Direct emissions from reforming of natural gas and indirect emissions of urea for different ammonia production technologies, cumulative values for all ammonia production capacity in EU28. If, in the case of 100% electrolysis,  $\text{CO}_2$  for urea production is sourced from non-fossil sources, the  $\text{CO}_2$  release is carbon neutral (indicated by the patterned area).

Currently, the use of urea fertilizer represents about 25%-30% of the total emissions from the production of ammonia [1]. There are multiple options to decrease the emissions related to urea use on soil. Firstly, (in the case of 100% electrolysis)  $\text{CO}_2$  from climate neutral, non-fossil sources could be used as feedstock. This could be supplied from direct air capture (DAC) or biogenic sources. However, no large scale DAC exists today and costs are still high. Additionally, DAC requires substantial amounts of electricity and land-use [1]. Secondly, more efficient use of fertilisers could help reduce the amount of fertilisers applied to soil, reducing the emissions in the use phase. Thirdly, one could shift away from urea towards other types of nitrogen fertilizer that do not release  $\text{CO}_2$  when applied to land, such as ammonium nitrate ( $\text{NH}_4\text{NO}_3$ ). It is important to note that, compared to urea, ammonium nitrate has the disadvantages of (1) more demanding handling and storage requirements, (2) explosion risk which could lead to trade restrictions and (3) a lower nitrogen density, which means that larger volumes of fertilizer would need to be transported.

Aside from the indirect emission from the use of urea, it is important to take into consideration the emissions from the electricity production required for electrolysis. Current electricity production in the EU28 is not yet zero-emission. It is possible that ammonia production facilities are connected directly (physically or virtually through power purchase agreements and certificates) to renewable electricity generation, such as a solar or wind park. However, in the short term it is not likely that this will yield a utilization factor of 90%, as assumed in this analysis. What is more, one should take into

account the effect of this renewable energy on the entire energy system if the availability is still limited. If electrolysis for fertilizer production is taking the renewable electricity for its own account, another source of electricity demand cannot use that renewable energy. This demand should then be supplied by conventional electricity production. Therefore, looking at the emission factor of electricity for each country can provide insight into the indirect emissions associated with local electricity production.

Emission factor data for the EU28 up to 2019 was obtained from the European Environmental Agency [24]. In order to achieve an emissions reduction of 55% by 2030 compared to 1990 levels, the emission factor of electricity production for EU28 as a whole must decrease accordingly. By 2050, it is assumed that all electricity production has reached an emission factor of zero. Emission factors for the years between 2019-2030 and 2030-2050 were obtained by linear interpolation. Country specific emission factors for the period 2019-2050 were also calculated, by assuming the emissions from electricity production in each country follow the same trend as the emissions from electricity production in the EU28 as a whole and taking the emission factor for each country in 2019 as a starting point.

Having quantified the three sources of CO<sub>2</sub> emissions (direct emissions from natural gas reforming and indirect emissions from urea use and electricity production), it is possible to calculate the total emissions of the different plant configurations over time and for each country. Figure 28 shows the result for the entire EU28. The black dotted line represents the emissions, assuming that all ammonia is produced using steam methane reforming without CO<sub>2</sub> capture, whereas the grey dotted line represents the emissions with CO<sub>2</sub> capture. The three blue lines show the evolution of emissions over time for the different electrolysis cases. Since the average emission factor in the EU28 is still relatively high in the near future, replacing all grey hydrogen with electrolysis using electricity from the grid would result in higher overall emissions until around 2028. However, with the emission factor decreasing as more and more zero-emission electricity production capacity is developed, electrolysis should lead to lower emissions than conventional hydrogen production in the long term.

The light grey area underneath the grey dotted line represents the emissions from the use-phase of urea. As explained previously, for the case of 100% electrolysis, there is no CO<sub>2</sub> stream from natural gas reforming that could be used for urea synthesis. If biogenic CO<sub>2</sub> or direct air captured CO<sub>2</sub> is used, these emissions would be offset, and the entire curve in Figure 28 can be shifted downwards by the height of the grey area. Or, if another nitrogen fertilizer is used instead of urea, such as ammonium nitrate, these use phase emissions can be avoided altogether.



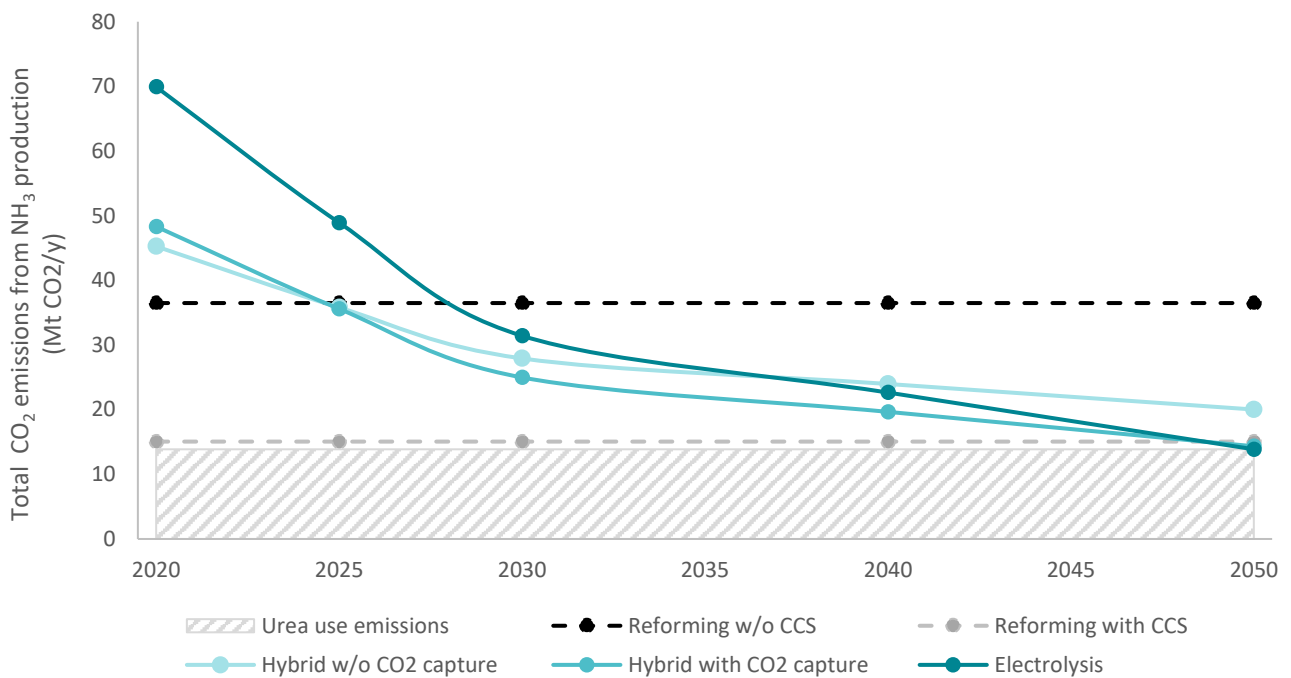


Figure 28: Direct and indirect CO<sub>2</sub> emissions if all ammonia production capacity in the EU28 is converted to a single production technology (hybrid or electrolysis), compared to the direct CO<sub>2</sub> emissions of reforming with and without CCS.

For each country, the moment in time where electrolysis is expected to lead to lower overall emissions than conventional ammonia production depends on the emission factor of the electricity mix in that country. To illustrate, the same graph is shown for two countries with substantially different emission factors: Austria (Figure 29) and Germany (Figure 30). Austria has a relatively low emission factor, due to a high share of hydropower. Therefore, ammonia production using hydrogen from electrolysis would already lead to net lower emissions in 2020 compared to conventional ammonia production. In contrast, Germany has a relatively high emission factor compared to the European average, causing electrolysis to fall below the emission level of conventional ammonia production around 2030. Note that the difference in total CO<sub>2</sub> emissions from ammonia production is due to the different ammonia production capacities in Austria and Germany.

In the previous graphs, the overall CO<sub>2</sub> emissions of converting the entire production capacity to one of the possible plant configurations were calculated for the period of 2020 to 2050. This underlines that sufficient capacity of near-zero electricity is essential to maximize the emission reductions in the fertilizer industry. However, calculating the emissions of converting all production capacity to 100% electrolysis in 2020 does not reflect reality. Similar to the analysis of Figure 26, one could interpret the three electrolysis cases as a 45%, 60% and 100% switch to renewable hydrogen for ammonia production. Assuming a gradual roll out of electrolyser capacity in the EU28, the emission reduction path could look something like the one shown in Figure 31. For the ammonia production industry to become completely decarbonized, all three sources of CO<sub>2</sub> emissions must be addressed.

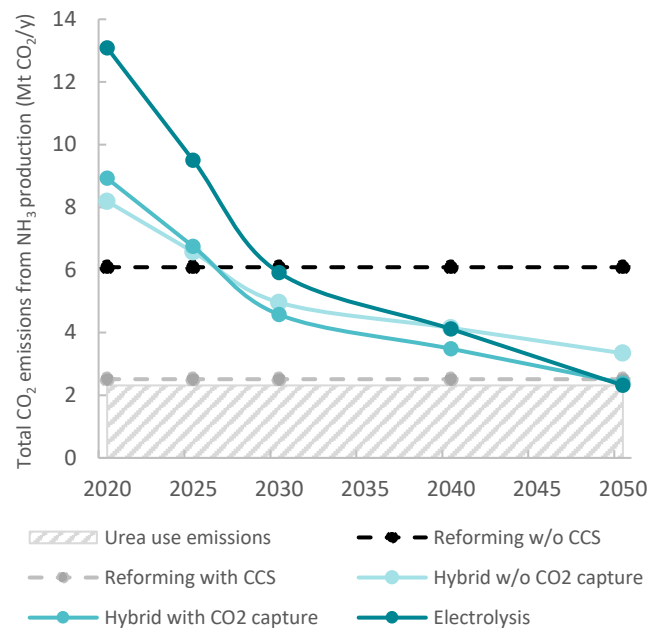
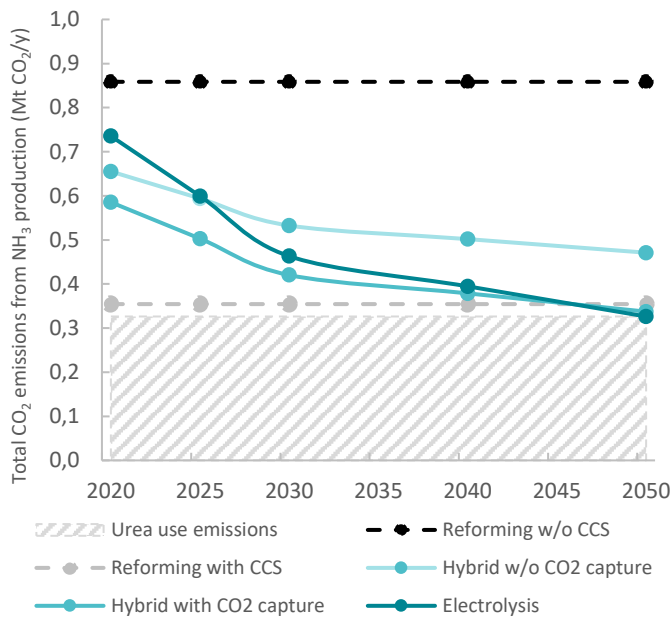


Figure 29. Direct and indirect CO<sub>2</sub> emissions if all ammonia production capacity in **Austria** is converted to a single production technology (hybrid or electrolysis), compared to the direct CO<sub>2</sub> emissions of reforming with and without CCS.

Figure 30. Direct and indirect CO<sub>2</sub> emissions if all ammonia production capacity in **Germany** is converted to a single production technology (hybrid or electrolysis), compared to the direct CO<sub>2</sub> emissions of reforming with and without CCS.

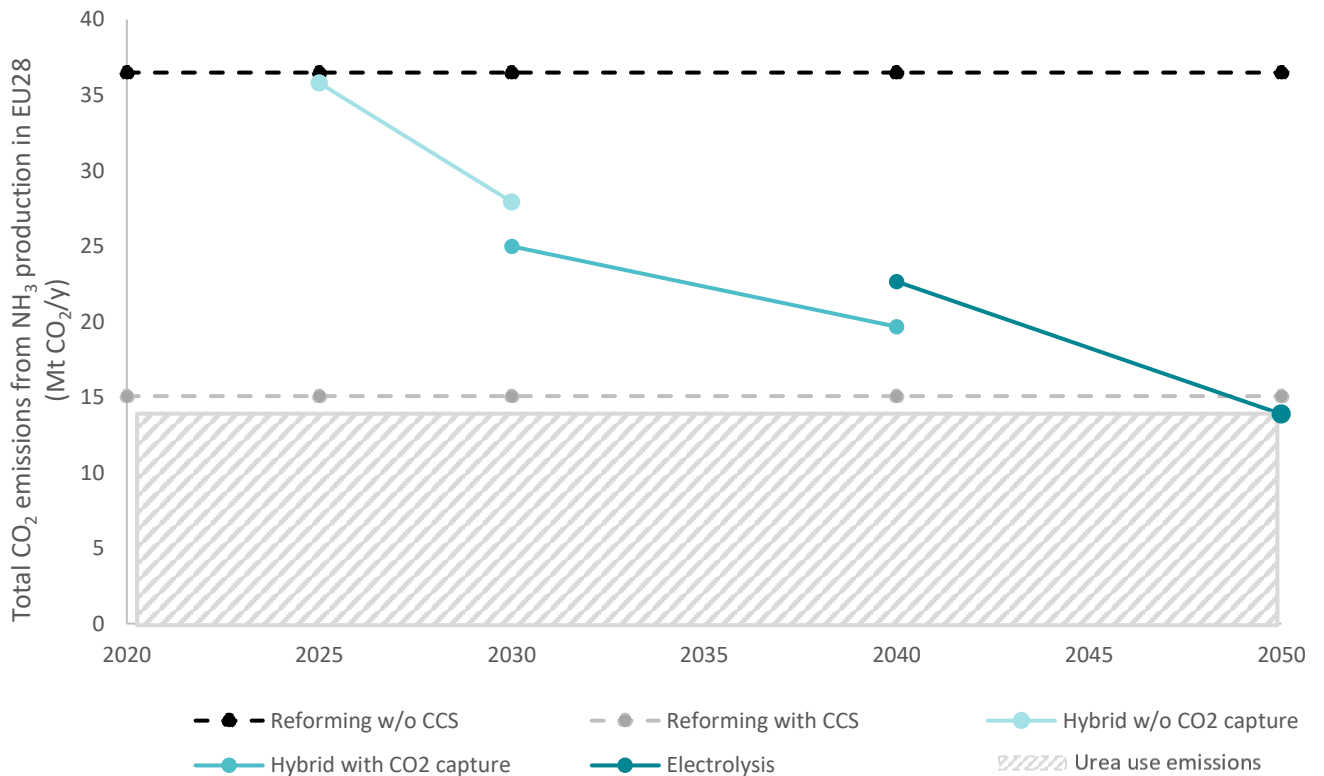


Figure 31. Gradual roll-out scenario of switching to renewable hydrogen over the period of 2025-2050.

## 5 Conclusions

The goal of this study was to understand under which technical, cost and environmental conditions hydrogen production through water-electrolysis can be a competitive alternative for the synthesis of ammonia, compared to natural gas-based hydrogen production. To analyze this, the break-even electricity price was calculated for the different plant configurations containing electrolysis, compared to the conventional reforming process. This showed the most important levers in the business case of renewable hydrogen for ammonia production.

First of all, the business case becomes more attractive if the natural gas price increases in the future, compared to the conventional process. For instance, with an increase of 50% (natural gas prices ranging from 34-42 €/MWh), the switch to electrolysis-based renewable hydrogen becomes more attractive, even when compared to the CCS option.

Secondly, the CO<sub>2</sub> price has a significant effect on the break-even electricity price for all plant configurations compared to the reference plant without CO<sub>2</sub> capture. Increasing the CO<sub>2</sub> price by 50% compared to the reference scenario (in which the CO<sub>2</sub> price increases from 24 €/tonne in 2020 to 125 €/tonne in 2040 and further to 170 €/tonne in 2050), break-even electricity prices are found to be in the range of 34 - 52 €/MWh for the hybrid configurations in the period 2030 - 2040, and even increase to values well above 60 €/MWh towards 2050. Comparable values for the full electrolysis variant range from 27 €/MWh in 2030 to 47 €/MWh in 2050. A combination of higher CO<sub>2</sub> prices with higher gas prices will of course lead to even higher values for the break-even electricity prices. In contrast, the effect of the CO<sub>2</sub> price is negligible if compared to the reference case *with* CCS, because the CO<sub>2</sub> price hardly affects its business case.

Thirdly, lower electricity network tariffs appear to have a significant positive effect on the break-even electricity price. A full exemption leads to an increase in the break-even price of more than 5 €/MWh.

It is expected that in the course of the period between 2030 and 2040 the renewable electricity costs will reach a level comparable to the required break-even electricity price for a competitive transition to renewable hydrogen, when compared with the reference case *without* CCS. At locations with optimal sun and wind conditions, this can be the case even earlier. However, if CCS is possible and allowed, and a switch to the fossil-based low-carbon hydrogen option is made first in view of rising CO<sub>2</sub> prices, then a switch to renewable hydrogen at a later stage seems more challenging. A CO<sub>2</sub>-price mechanism alone provides insufficient incentive for the deployment of green hydrogen in ammonia production if existing ammonia production plants are already equipped with CCS. Other incentives are then needed for transitioning all fossil hydrogen based ammonia production to production with renewable hydrogen.

Converting existing ammonia production capacity from natural gas reforming to electrolysis requires a considerable increase in amount of near-zero-emission electricity, in order to lead to a reduction in CO<sub>2</sub> emissions. This transition would place a fairly large burden on current electricity production in the countries where ammonia production is currently located. Furthermore, the electricity demand for electrolysis-based ammonia production would require a significant share of the projected capacities of solar and wind power production in the EU28. Especially, considering the additional demand for zero-emission electricity from other major electrification options such as electrical boilers in the industry, electric vehicles and residential heat pumps. Next to the limited supply of zero-emission electricity, infrastructure and land-use constraints can pose a challenge for the production of green hydrogen in Europe. It is possible that future hydrogen demand will be met by importing it,



rather than producing it locally or that ammonia production would be relocated to countries with more abundant renewable energy production capacity and infrastructure.

For the ammonia industry to become completely decarbonized, all three sources of CO<sub>2</sub> emissions must be addressed: direct emissions from steam methane reforming, indirect emissions from urea use in agriculture and indirect emissions from electricity generation for electrolysis. The direct emissions can be reduced by (partially) substituting hydrogen production from natural gas reforming, by electrolysis or by implementing CCS. The indirect emissions from urea use can be reduced by (1) using a climate neutral source of CO<sub>2</sub> for urea synthesis, in combination with hydrogen from water-electrolysis, (2) by making more efficient use of the fertilizer, so less urea needs to be applied to soil or (3) by eliminating urea use entirely by transitioning to other nitrogen-based fertilizers, such as ammonium nitrate. The indirect emissions from electricity generation can be eliminated by making use of a zero-emission source of electricity. To arrive at a fully sustainable zero-emission electricity system, further expansion of renewable electricity supply is clearly needed in many of the EU28 countries.

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