2023

Market state and trends in renewable and low-carbon gases in Europe

A Gas for Climate report

December 2023

GAS FOR CLIMATE
A path to 2050

Guidehouse

Imprint

Authors:
Eugenia Maria Morino, Agustin Roth, Jaap Peterse

Date:
December 2023

Contact:
Guidehouse
Stadsplateau 15, 3521 AZ Utrecht
The Netherlands
+31 30 662 3300
guidehouse.com

Photo Credits:
© Ubonwan / Adobe Stock

Design:
Carolyn Gray, Stephanie Kandathiparambil

Executive summary

The European Union (EU) aims to fully decarbonise its economy by 2050, requiring an extensive transition of energy generation, infrastructure, and usage. In the midterm, the EU is targeting a 55% reduction in greenhouse gas (GHG) emissions by 2030 compared to 1990 levels. As indicated in our 2021 Market State and Trends report, these ambitions will require significant investment in energy efficiency, renewable energy, new low-carbon technologies, and transport and storage infrastructure. There is also the need for closer and smarter integration of electricity and gas sectors and their respective infrastructure.

In various reports over the past years, the Gas for Climate consortium has shown that a decarbonised European energy system will be based on the interplay between renewable electricity and renewable and low-carbon gases to supply all sectors with energy at the lowest possible societal cost, while preserving the security and reliability of the energy system. REPowerEU, as a reaction to the Russian invasion of Ukraine only emphasized this. Policy and market actions are required to achieve the rapid scale-up and integration of renewable and low carbon gases across Europe.

This edition of the Market State and Trends report is an addition to the 2020 and 2021 reports, highlighting the most relevant market developments of the past two years. Next to the trends for biomethane and hydrogen, this report for the first time also covers CO_2. It focuses on the market trends that were highlighted in the past reports and looks ahead to innovation and technology for all three gases showcasing upcoming developments.

As highlighted in REPowerEU, biomethane can play a key role in diversifying gas supply sources, boosting EU energy independence and reducing exposure to natural gas prices volatility. The European Commission targets 35 billion cubic meters (bcm) of biomethane production within the EU by 2030. In 2022, the EU biomethane production capacity was 3.4 bcm. Large investments across EU are currently unlocking biomethane potential, however further financing is required as planned investments cover only 20% of future needs. Gasification technologies are at the forefront of commercialisation and will contribute to achieve the 35 bcm target. Enhanced pipeline connection between the biomethane production plants and the gas network is needed to ensure a larger uptake of biomethane. Catalysing biomethane demand with blending obligations, following the Dutch obligation example and setting more ambitious NECPs targets is critical to achieve the 2030 biomethane scale-up.

The EU is trying to lead the hydrogen economy by setting sustainability criteria, demand quotas and manufacturing and supply support policies. To meet the 10 Mt of domestic renewable hydrogen set by the REPowerEU Plan, the EU should reach almost 100 GW of installed electrolyser capacity by 2030. The EU will need to sort out different barriers, as there is still a considerable gap between the current installed capacity and the projections for 2030. The high interest rates and inflation observed since 2022 add challenges as leveraging debt is more expensive, resulting in increased overall project costs. Companies in the EU are implementing innovative approaches, such as installing electrolysers directly at wind offshore sites and developing hydrogen pipelines to transport the product to shore. Innovation on the electrolyser side coupled with power system integration solutions will enable a faster market ramp-up. Moving forward, the EU should focus on developing interconnected European hydrogen infrastructure, such as transport pipelines, to strengthen its market. At the same time storage sites and improved ports infrastructure is fundamental to enable long-distance shipping of hydrogen and derivatives.

Existing synergies between carbon capture, utilisation and storage (CCUS) development and low-carbon gases, such as biomethane and hydrogen highlighted in this report, should be further leveraged as climate mitigation solutions to achieve net-zero. Currently, CCUS projects face significant barriers to scale-up, such as lack of CO_2 network infrastructure from point sources to terminals, large lead times to get administrative permits and develop sites, geological data assessment, and high upfront investments. Currently CO_2 capture potential for permanent sequestration in onshore and offshore locations is largely untapped, with only three large-scale CCS projects undertaking positive Final Investment Decision (FID). More CCUS projects are expected to concretise in the next decade, as more than 60 projects have been announced over the past five years across Europe. There is an expanding gap between the growing need for and the availability of CO_2 infrastructure. Timely and coordinated action between the private sector and governments can catalyse the deployment of CCUS projects towards reaching the 50 Mt/y CO_2 injection target by 2030 as part of the Net Zero Industry Act and accelerate the synergies further.

From a policy perspective, the EU is implementing an ambitious agenda to reduce emissions by at least 55% by 2030. In consequence, a large revision of policies and regulations has been undergoing at the EU level to ensure the climate and energy goals are reached on time. Many of these policies and regulations have a direct impact on the market of renewable and low-carbon gases, as they introduce quotas, blending obligations, mandatory targets, regulate infrastructure development and give guidance for network operations. A clear and solid regulatory framework will be fundamental to enable a transparent, rapid, and fair accelerated ramp-up of renewable and low-carbon gases.

A decarbonised European energy system will be based on the interplay between renewable electricity and renewable and low-carbon gases to transport, store and supply all sectors with energy. The future energy system and its interactions are becoming increasingly complex, and this report shows how several projects and technologies are developing at the intersections between biomethane, hydrogen and CO_2. The increasing interactions between gases will also be necessary to come up with cost-efficient solutions that match local supply, demand and infrastructure needs.

Biomethane

Biomethane **production continues to grow** reaching 4.2 bcm in Europe, with 3.4 bcm in the EU-27 in 2022, but **additional initiatives** are needed to reach the 35 bcm target in 2030 set by the REPowerEU plan

Transmission and distribution **pipeline** connection is needed to ensure a **larger uptake** of biomethane

Gasification technologies are gaining momentum and hold large production **potential**

Hydrogen

Reaching the 10 Mt of domestic renewable hydrogen (set by REPowerEU Plan) requires almost **100 GW of installed electrolyser capacity** by 2030 but projections lag behind target

The rapid development of an interconnected **European hydrogen infrastructure** is fundamental to enable a competitive, liquid, pan-European hydrogen market

Offshore hydrogen production projects with transport infrastructure to shore can **facilitate the integration** of increasing **renewable energy** capacity in the energy system

CO_2

Existing **synergies** between CCUS development and low-carbon gases (biomethane and H_2) can be **further leveraged** as climate mitigation solution to achieve net-zero

CO_2 capture potential for permanent sequestration in onshore and offshore locations is currently **largely untapped**

CCUS project development across Europe is **gaining momentum** with more than **60 projects** announced in the past five years

Policy developments

The new policy architecture of the **Fit-for-55 Package will have a large impact on the entire value chain** of hydrogen, biomethane and CO_2

REFuel EU Aviation and FuelEU Maritime set important obligations that **can unlock further RFNBOs uptake**

To facilitate the certification of RFNBOs, the **EU Commission defined the sustainability criteria** to follow

Glossary

bcm	Billion cubic meters
BECCS	Bioenergy with Carbon Capture and Storage
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
CCUS	Carbon Capture, Utilization, and Storage
CDR	Carbon Dioxide Removal refers to the technologies that remove carbon from the atmosphere and enable achieving negative emissions.
CEF-E	Connecting Europe Facility - Energy
DACCS	Direct Air Carbon Capture and Storage
EC	European Commission
EU ETS	European Union Emissions Trading System
GHG	Greenhouse gas
IPCEI	Important Projects of Common European Interest
LOHC	Liquid Organic Hydrogen Carriers
Low-carbon hydrogen	Hydrogen produced from non-renewable sources with GHG savings of at least 70% compared to the fossil benchmark of 94.1 $gCO_2eq/MJ\ H_2$ (across the full lifecycle).[1] An example would be the production of hydrogen via steam methane or autothermal reforming in combination with high carbon capture rates.
NZIA	Net-Zero Industry Act
PCI	Projects of Common Interest
Renewable hydrogen	Hydrogen produced from renewable electricity (e.g. electrolysis) or from renewable energy (e.g. steam reforming of biomethane). "Renewable hydrogen" is defined in the Delegated Act on Article 27 of the Renewable Energy Directive II (RED II) as Renewable fuel of non-biological origin (RFNBO).
RFF	Reverse Flow Facilities
RFNBO	Renewable Fuel of Non-Biological Origin
TEN-E	Trans-European Networks for Energy
TPA	Third-Party Access
TSO	Transmission System Operator

1 European Commission (2021). Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (Link)

Table of contents

1. Introduction

The European Union (EU) aims to fully decarbonise its economy by 2050. This will require an extensive transition of energy generation, infrastructure, and usage. In the midterm, the EU is targeting a 55% reduction in greenhouse gas (GHG) emissions by 2030 compared to 1990 levels. As indicated in our 2021 Market State and Trends (MST) report, these ambitions will require significant investment in energy efficiency, renewable energy, new low-carbon technologies, and transport and storage infrastructure.[2] There is also the need for closer and smarter integration of electricity and gas sectors and their respective infrastructure. In various reports over the past years, the Gas for Climate consortium has shown, that a decarbonised European energy system will be based on the interplay between renewable electricity and renewable and low-carbon gases to transport, store and supply all sectors with energy at the lowest possible societal cost while preserving the security and reliability of the energy system.[3]

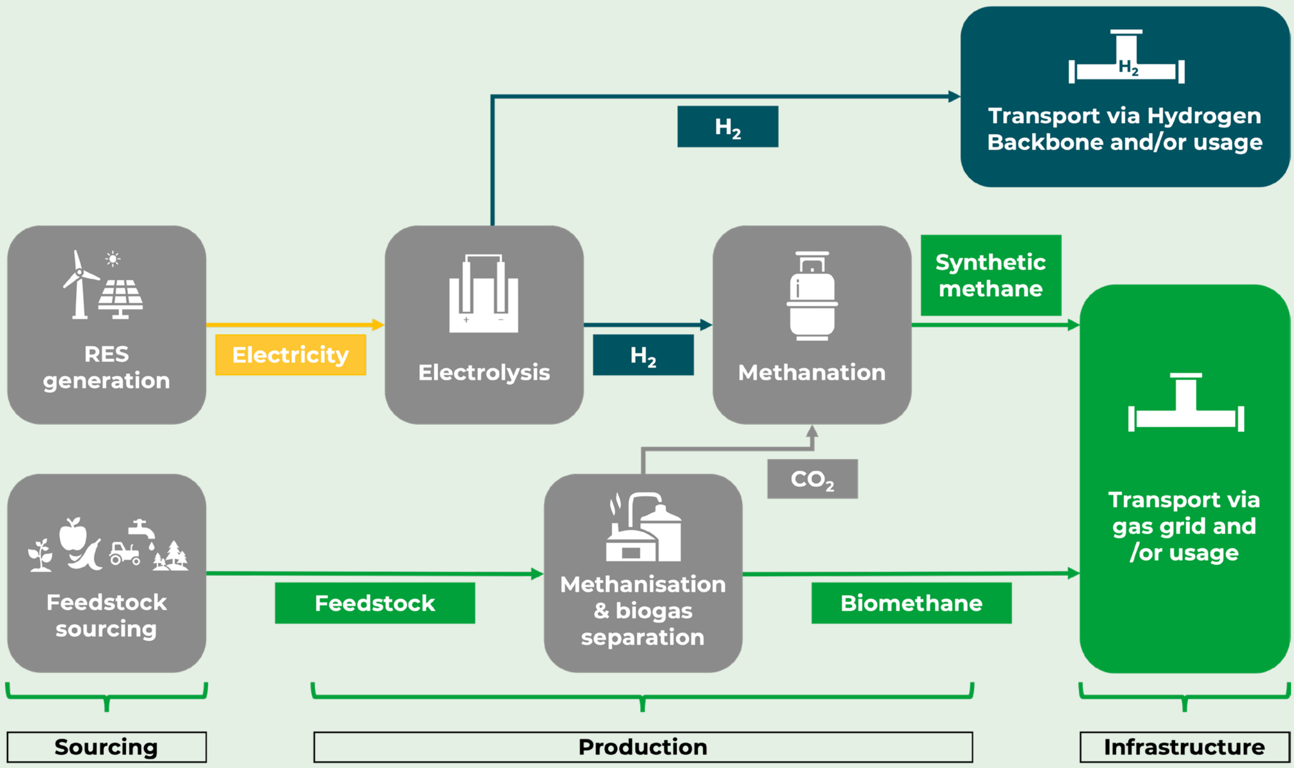
Following the Russian invasion of Ukraine early 2022, the EU published its REPowerEU plan. This plan has confirmed and emphasised the important role of renewable gases, not only for the energy transition, but also to reduce the dependency on Russian natural gas imports and foster energy supply reliability. A bottom-up study by the European Hydrogen Backbone (EHB) identified 14.7 Mt of demand by 2030, representing tangible and achievable projections based on national targets, market developments, and announced projects. To achieve the ambitious policy goals, policy and market actions are required to enable a rapid scale-up and integration of renewable and low carbon gases across Europe at the lowest possible cost.

In our 2020 and 2021 MST reports, we assessed the state of deployment and trends towards future scale up and cost reductions. This 2023 report update highlights the most relevant market developments of the past two years. Next to the trends for biomethane and hydrogen, this 2023 report for the first time also covers CO_2. This topic was addressed by the consortium in the recent paper on "Best practices for CCUS infrastructure in Europe"[4], as the importance of these technologies towards the net-zero transition is generating more interest.

The future energy system and its interactions are becoming increasingly complex. Several projects and technologies are developing at the intersections between biomethane, hydrogen and CO_2. Smart integration of technologies can lead to local decarbonisation solutions. A schematic example of how these gases could interact is shown in Figure 1 below. These increasing interactions between gases will also be necessary to come up with cost-efficient solutions that match local supply, demand and infrastructure needs.

2 Gas for Climate (2021). Market state and trends in renewable and low-carbon gases in Europe (Link)
3 All reports published by the Gas for Climate consortium can be downloaded at the following link.
4 Gas for Climate (2023). Best practices of CCUS infrastructure in Europe (Link)

Figure 1
Example of interactions between production of renewable gases and infrastructure



This report is structured in five chapters. In chapter 2 (biomethane), chapter 3 (hydrogen) and chapter 4 (CO_2), the market state and trends of these gases are described. The chapters are broken down into a section on market, and a section on innovation and technology. Lastly, in chapter 5, key policy developments are described with a focus on policies that have a large influence on market developments for renewable and low-carbon gases.

2. Biomethane trends

Key takeaways

Biomethane production continues to grow reaching 4.2 bcm in Europe, with 3.4 bcm in the EU in 2022, but additional initiatives are needed to reach the 35 bcm target in 2030 set by the REPowerEU plan. Most of the EU biomethane production is in Germany, France, Italy, Denmark, the Netherlands and Sweden, where the renewable gas is consumed nationally, with limited cross-border trade. Further acceleration beyond current plans is needed to achieve the REPowerEU 35 bcm biomethane target by 2030, as planned investments cover only 20% of future needs and published NECPs 2030 production targets sum up to 20.2 bcm. Catalysing biomethane demand with blending obligations, development of more efficient technologies, more ambitious NECPs targets, and increased natural gas substitution uses is critical to achieve the 2030 target.

Transmission and distribution pipeline connection is needed to ensure a larger uptake of biomethane. Critical measures taken ahead of large investment needed for high-pressure grid connection include mapping the optimised connection choices and production potential and lowering the pressure level at the local distribution grid, include a buffer storage in the distribution network and network meshing between local consumption areas. When applicable, reverse flow facilities are a solution to scale-up the ease of connecting anaerobic digestion biomethane plants to the grid.

Gasification technologies are gaining momentum and hold large production potential. Commercial-scale gasification projects are coming online brining increased efficiency, higher conversion rates, easier connection to the high-pressure grid and ability to handle a wider range of feedstocks, compared to the conventional anaerobic digestion production.

2.1 Markets

2.1.1 Supply

Biomethane production continues to grow, nevertheless further acceleration is required to achieve REPowerEU targets

As highlighted in the REPowerEU Plan, biomethane can play a key role in diversifying gas supply sources, boosting EU energy independence and reducing exposure to natural gas prices volatility.

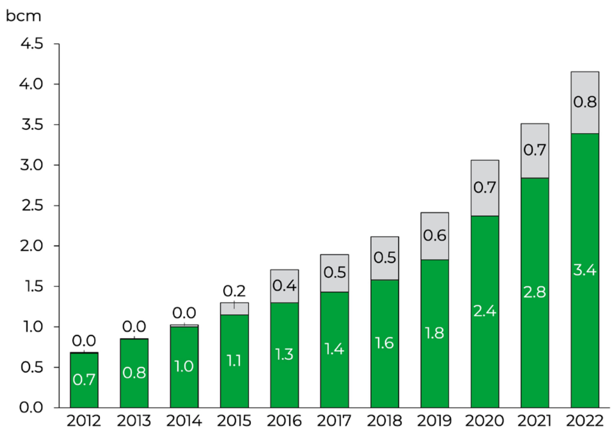
Expanding the production and uptake of biomethane, which is a renewable and dispatchable energy source, contributes to mitigating the climate crisis. The European Commission has the ambition to achieve an annual biomethane production of 35 billion cubic meters (bcm) in the EU by 2030. Currently, Europe's biomethane production capacity ranges around 4.2 bcm per year, with 3.4 bcm being produced in the EU, as shown in Figure 2.[5] To fulfil the 2030 target, biomethane production must almost increase tenfold in the next seven years.

5 European Biogas Association (2023). Annual Statistical Report (Link)

The Gas for Climate assessment published in 2022 on biomethane production potentials in the EU shows that enough sustainable feedstocks are available in the EU-27 to meet the target, with up to the total production potential being 41 bcm of biomethane potentially being produced in 2030.[6]

Based on the 2030 National Energy and Climate Plans (NECPs), the European Biogas Association (EBA) estimated the anticipated EU-27 biomethane production to be 20.2 bcm in 2030.[7] This estimation highlights a biomethane product gap of 10.3 bcm. Hence, critical actions need to be taken at national and European level to achieve the 35 bcm target in EU and facilitate biomethane uptake, trade and supply beyond 2030.

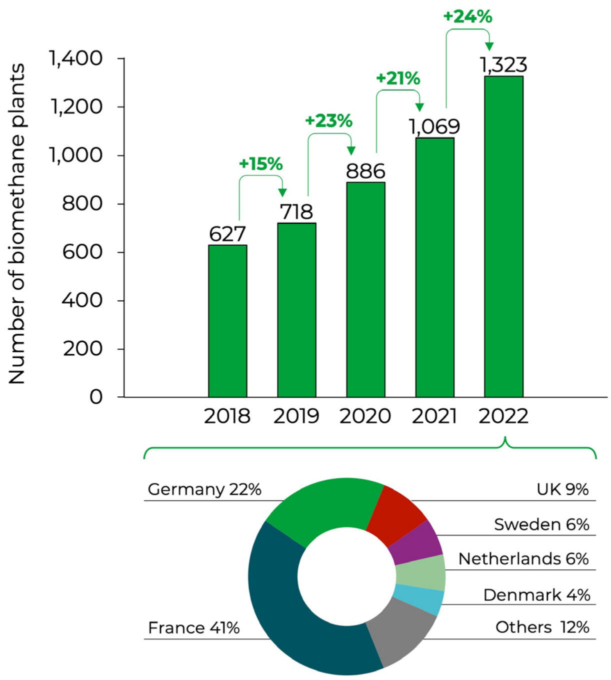
Figure 2
European biomethane production (EBA) in EU (green) and the rest of Europe[8] (grey)



Germany is the EU leader in biomethane production in terms of volume, while France shows the largest number of plants installed

As documented by the European Biogas Association (EBA), the number of operational biomethane plants has reached a total of 1322 producing facilities in Europe in 2022, producing around 4.2 bcm of biomethane across Europe. New biomethane plant installations more than doubled over the past five years, following a growing trend similar to the one observed in the 2021 MST report. Almost all biomethane plants are via anaerobic digestion, with 20% of the EU biogas upgraded to biomethane in 2022.[9] Thermal gasification with biomethane synthesis is gaining momentum as discussed in the technology section below.

Figure 3
Number of total biomethane plants in Europe between 2018-2022 (EBA)

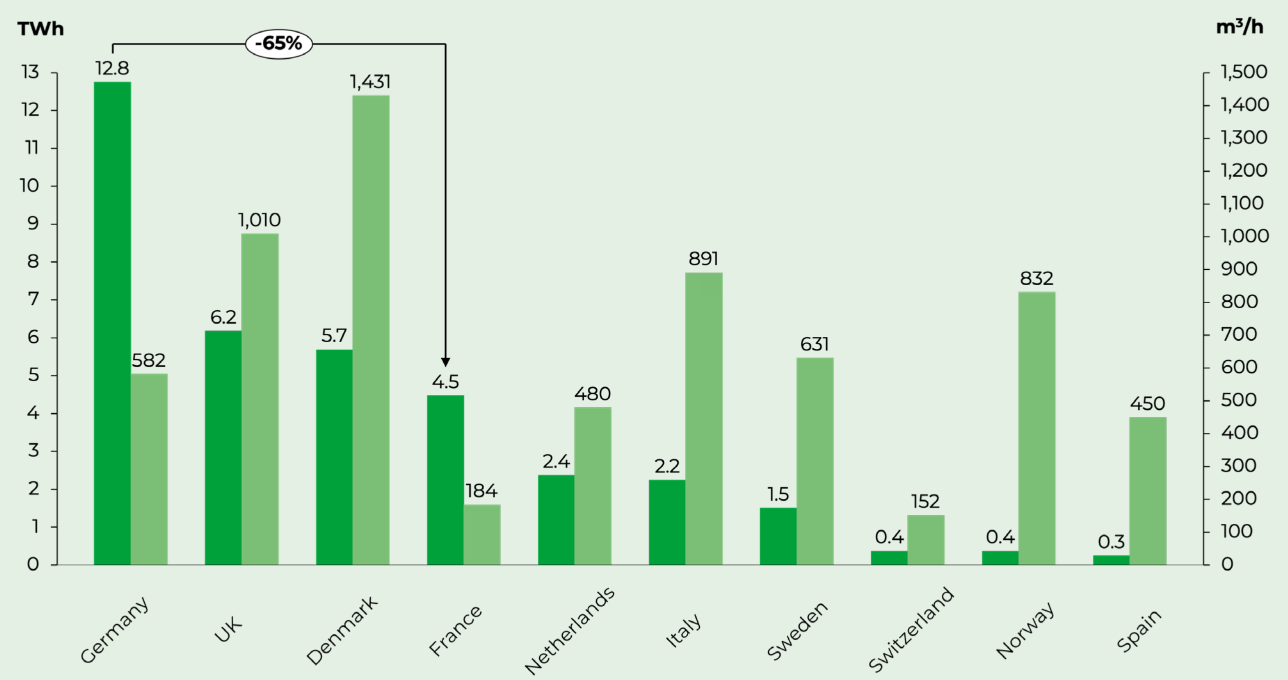


However, biomethane production developments differ significantly between EU countries, mainly driven by the national strategies and financial support mechanisms in place. Figure 3 shows the development in number of biomethane plants. France continues to see the largest growth in biomethane plants in recent years from 131 in 2020 to 514 plants in 2022. France now has the most biomethane plants in Europe, surpassing Germany (254 facilities as of end 2022).

6 Gas for Climate (2022). Biomethane production potentials in the EU (Link)
7 European Biogas Association (2023). Annual Statistical Report (Link)
8 Rest of Europe includes Iceland, Norway, Serbia, Switzerland, Ukraine and the United Kingdom
9 European Biogas Association (2023). Annual Statistical Report (Link)

The difference between Germany and France in number of operational biomethane plants is not reflected in terms of overall biomethane production (TWh), with Germany being the European leader in biomethane production. In 2022 Germany produced around 30% of the total European biomethane. The discrepancy between number of biomethane plants and TWh production depends on the average installed capacity of the biomethane plants. Germany has an average plant size capacity of 582 m³/h whereas France has tendency for smaller scale installation, with an average size capacity of 184 m³/h.

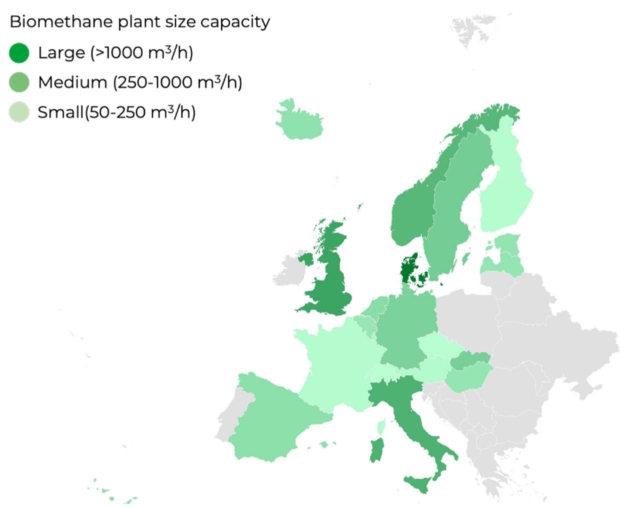
Figure 4
Biomethane production (dark green) and average plant size (light green) in top 10 EU countries in 2022[9]



Biomethane plant size varies largely across Europe, depending on country and policy framework

Biomethane plant sizes vary largely across EU countries, as Figure 5 shows. The previous MST report highlighted a tendency towards small scale biomethane plants for new installations, mostly driven by France. This development confirms that upgrading biogas to biomethane is becoming more economically feasible, even in small-scale projects. On average, plant sizes across Europe range around 460 m³/h of capacity.[10]

Figure 5
Average biomethane plant capacity size in 2022 for selected EU countries (EBA)



10 European Biogas Association (2023). Annual Statistical Report (Link)

In terms of average installed biomethane capacity, Denmark, the UK and Italy show the largest average capacity size, ranging between 890 and 1400 m^3/h in 2022, while France, Finland and Switzerland the smallest: between 150 and 185 m^3/h. Germany also shows a trend to medium to large scale of biomethane plant size.

The large difference in plant size across EU reflects the current fragmentation of the biomethane market, with different characteristics of national markets and large disparities in market maturity between countries. Different plant size also implies the cost structure for each project differs, with total CAPEX of €5-8 million for small scale, €7-25 million for medium and more than €25 million for large scale.[11]

Gasification technologies are gaining momentum as commercial-scale projects are coming online

As discussed in the 2021 MST report, biomethane production via gasification is becoming commercially viable. Gasification technologies hold substantial potential, with thermal gasification estimated potential of 2.9 bcm in 2030 for EU-27, increasing to 60 bcm in 2050.[12] Even more potential can be unlocked by looking at additional feedstocks and technologies, for instance hydrothermal gasification of wet feedstocks, including organic wastes and residues and alternative production technologies, such as synthetic methane.

The two main alternatives to anaerobic digestion (AD) combined with biogas upgrading for biomethane production are gasification technologies, including thermal and hydrothermal gasification. Thermal gasification with biomethane synthesis is not yet commercially available, but it is expected to become commercially available in the coming years and holds large potential to scale in the medium to long term.

- Thermal gasification or pyrogasification (pyrolysis gasification) with a high Technology Readiness Level (TRL) where dry and solid waste is treated at low pressure, slightly below atmospheric pressure and high temperature 800-850°C to produce syngas. The following step is methanation at 300-350°C and 2-5 bar. Pyrogasification makes it possible to transform residues and solid waste that are currently poorly recovered into renewable, low-carbon gases: non-recycled plastics, wood waste, and solid recovered fuels.[13] The biomethane produced form thermal gasification can be fed in the distribution network.

- Hydrothermal gasification or supercritical water gasification (SCW). This technology is suitable to treat wet and liquid feedstock of both organic and non-organic origin. SCW gasification treatment ranges between 300-400°C and pressures over 221 bar. At higher temperatures (600-700°C) higher biomethane conversion is achieved, as in non-catalytic SCW gasification. Compared to thermal gasification, SCW carries a large CO_2 footprint decrease potential as it can be used to treat non-biogenic liquid streams, such as certain industrial sludges. The main benefits of SCW gasification, compared to AD, are higher conversion rates (above 90% depending on the feedstock quality) and the high-pressure gas grid injection, as reconversion is not required.

Both gasification technologies are ready to scale-up and capture a bigger share of future biomethane production. A prime example of this development scale-up is the commercial thermal gasification plant in Salamander developed by ENGIE and the CMA CGM group with an output of 150 GWh/y of biomethane in 2026, with a planned scale-up towards 800 GWh in the coming years. The extent to which gasification technologies will capture the potential depends on whether they can reach the operational and production costs of AD.

11 Biomethane Industrial Partnership (2023). A vision on how to accelerate biomethane project development (Link)
12 Gas for Climate (2022). Biomethane production potentials in the EU (Link)
13 GRTgaz (2023). Pyrogasification and hydrothermal gasification (Link)

Large investments across Europe are unlocking biomethane potential

Extensive investments across Europe are needed to achieve the REPowerEU target of 35 bcm of biomethane production by 2030 in EU. The investments range required to fully unlock biomethane potential are in the range of €83 billion, depending on plant location, size and feedstock employed.[14] The EBA Biomethane Investment Outlook confirms that investments are materialising, with around €18 billion already earmarked for investment in biomethane production. Between 2023 and 2025, €4.1 billion are due to be invested, €12.4 billion will be unlocked between 2026 and 2030, and a further €1 billion investment is expected in an unspecified timeframe.

Scaling-up European biomethane production to 35 bcm requires an even higher private and public funding mobilisation, to ensure the construction of around 5000 additional plants across Europe and facilitate the transition to a wider range of sustainable biomass feedstock.[15] The required investment will provide additional system-wide benefits worth up to €7.9 billion. These include energy security, GHG emissions reduction, improved soil health, potential replacement for synthetic fertilisers, and enhanced waste management.[16]

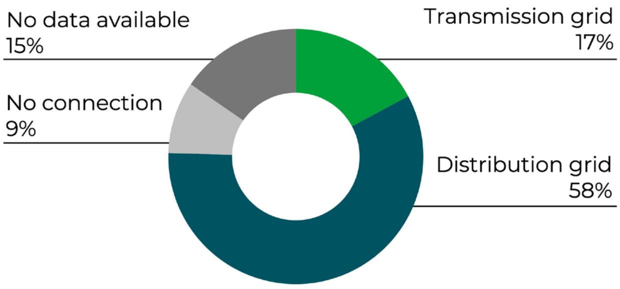
The €83 billion range investment to fully unlock 35 bcm of biomethane is estimated assuming the additional 5000 medium and large-scale anaerobic digestion plants. With the acceleration of more efficient technologies such as thermal and hydrothermal gasification discussed above, the investment required might vary. A timely development of thermal and hydrothermal gasification production might, at least partly, fill the gap between needed and planned investments in anaerobic digestion, as it enables higher volumes of biomethane production.

2.1.2 Infrastructure and storage

The majority of biomethane plants are connected to the existing gas grid, further connection is required to achieve 35 bcm

According to EBA latest statistical report, the vast majority of biomethane plants in Europe are connected to the transmission or the distribution pipelines. Out of the 1323 operational plant in 2022, cumulatively 998 plants are grid-connected as Figure 6 illustrates. More information on the connection shares below:

Figure 6
Share of biomethane plants connected to the grid in [%], 2022 (EBA)



Following the growing biomethane trend, the share of biomethane production plant connected to the distribution and transmission grid is expected to increase in coming years. The connection to the transmission grid will be facilitated if additional reverse-flow facilities will be implemented, this is the case for anaerobic digestion or thermal gasification plants connected to the distribution grid. Due to their large scale, thermal gasification plants will need a connection to the transmission network, with relatively moderate compressor costs per kWh of biomethane produced. Production via hydrothermal water gasification technologies generate biomethane at high pressure, ready to be injected in the high-pressure gas network. Additional grid planning measures are analysed in the section below.

14 European Biogas Association (2023). 1st EBA Biomethane Investment Outlook (Link)
15 European Biogas Association (2022). Delivering 35 bcm of biomethane by 2030 (Link)
16 European Biogas Association (2023). Beyond energy – monetising biomethane's whole-system benefits (Link)

Measures to support grid planning are needed to scale-up the ease of connecting biomethane plants to the grid, including reverse flow facilities for AD

Biomethane can be injected in the gas grid without the need for retrofitting, which is a major advantage. Reverse flow facilities (RFF) are located at the intersection of the transmission and the distribution grid and allow for physical bidirectional flows from the distribution to the transmission grid, and vice versa. As discussed in the 2021 MST Report, if biomethane injected into the low-pressure distribution grid is higher relative to the local consumption, the biomethane is compressed and re-injected into the high-pressure transmission grid. This ensures more flexibility for the gas system and expands the possibility to develop additional biomethane plants that otherwise could not be realized. RFF are needed for production technologies in which direct injection to the transmission grid is not possible. Biomethane produced via AD requires RFF, compared to SCW gasification in which RFF is not needed. Reverse flow facilities are not always necessary depending on the degree of interconnection in a country's gas grid, which can reduce the need for compression.[17]

However, investment in reverse flow facilities is not the only option to accommodate new productions plants connected to the grid. Network operators in some countries have been developing, testing and using an array of measures to anticipate new investment in the networks: (1) mapping of best possible network connections in relation to biomethane potential; (2) lowering the pressure level in the local distribution grid; (3) buffer storage in the distribution network; (4) network meshing between local consumption areas.

Measure (1) helps to anticipate how current and future biomethane production projects could be connected to either the transmission or the distribution grid, and whether the connection could be shared (pooling) or not. For instance, in Denmark and the Netherlands there is the trend of limiting the number of connections to the lower pressure grid to avoid congestion in summer times. In France, the gas TSOs and DSOs cooperate with each other to implement this mapping exercise resulting in shared maps of biomethane potentials and potential future grid connections.

Measure (2) is helpful to counterbalance the increase in pressure on the local grid caused by small mismatches in local production and consumption. It has been implemented in France.

Measure (3) is one step further in accommodating time-limited production/consumption imbalance in the local grids. Buffer storage can store extra-production of biomethane for a short number of hours, preventing a break in the injection of biomethane during evenings, nights or over weekends when the consumption is slightly lower than production volumes.

Measure (4) requires investment in new local pipelines meshing neighbouring consumptions areas. As an example, the program "FLORES" in France is rolling the first units of local buffer storage. In some instances, the program implemented this as an additional solution on top of network meshing to address different levels of network congestion risk.[18]

17 Gas for Climate (2022). Manual for National Biomethane Strategies (Link)
18 See for instance, this example in Brittany, France: Fougères Agglomération (2023). Green gas storage: a first in Brittany in the Fougères Agglo Area (Link)

2.1.3 Demand

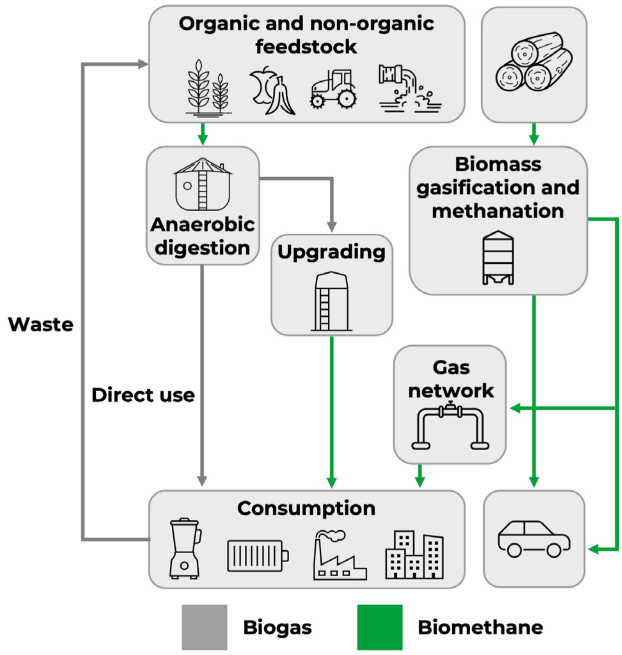
Biomethane has a large role in displacing existing natural gas use

European biomethane demand is growing. The main reason are incentives to reduce GHG emissions and ensure security of supply by using low-carbon and renewable gases (such as biomethane) instead of natural gas. Currently around 4.2 bcm of biomethane are produced in Europe, however the biomethane potential remains to some extent untapped. In our previous study quantifying biomethane potentials, we estimated the European biomethane potential at 45 bcm in 2030 and 165 bcm by 2050. Even more potential can be unlocked by including additional feedstocks and technologies, such as synthetic methane.[19]

As discussed in the 2021 MST Report, the IEA estimates an overall European production potential for biomethane of 1,350 TWh, which is much higher than the estimated demand in 2040: 140 TWh in the Stated policy scenario and 419 TWh in the Sustainable development scenario.[20] This indicates there is significantly more potential for the biomethane production and uptake sector to grow.

Biomethane is an extremely versatile renewable alternative as it can be used to displace existing natural gas use without the need of retrofitting. Sectors in which biomethane is currently employed and will be further used include (1) industry as natural gas substitute in chemical, steel, and food and beverages industries, (2) clean electricity generation as balancing power system to shave renewable generation intermittency, (3) transport especially for heavy duty and maritime sectors, and (4) residential sector, for instance for heating and cooking.

Figure 7
Biogas (grey) and biomethane (green) production pathways and demand use[21]



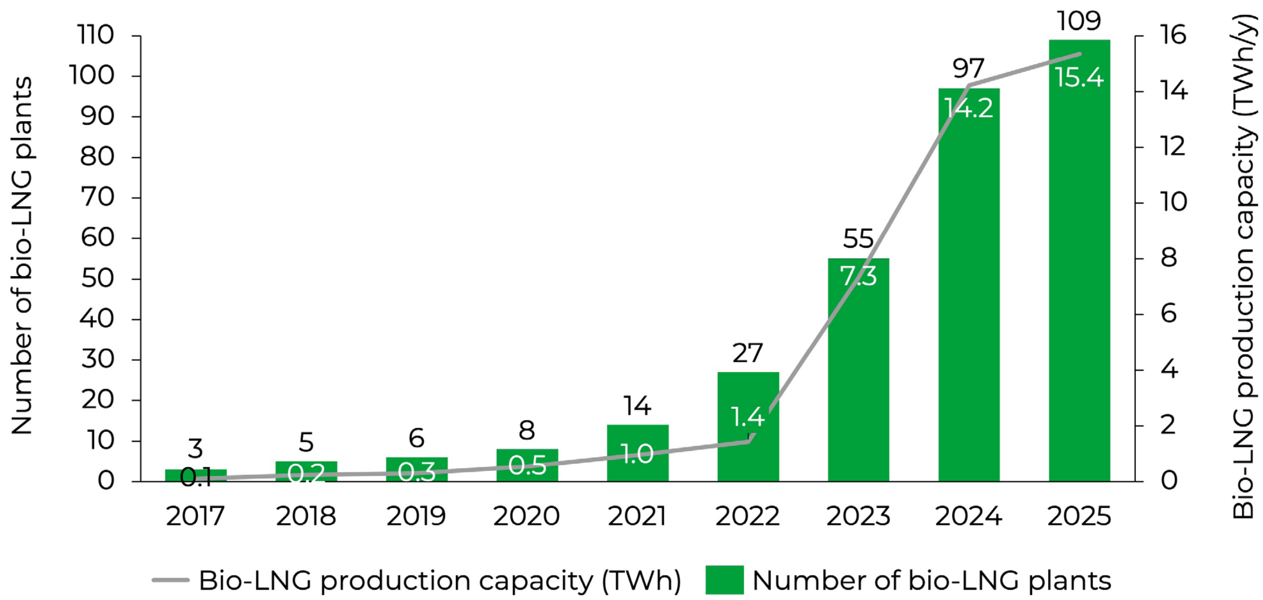
Bio-LNG use in road and maritime transport is on the rise

One of the end uses discussed above is the application of biomethane in the transport sector. Biomethane can be used as bio-CNG (compressed natural gas) in road transport or as bio-LNG (liquified natural gas) in heavy duty and maritime transport. As remarked in the 2021 MST Report, the production of bio-LNG is growing rapidly in Europe.

Figure 8 shows the fast uptake of bio-LNG plants and the total production capacity in TWh. In 2023, the number of bio-LNG plants installed is expected to more than double compared to 2022. A similar fast-paced trend is expected for 2024. The future predictions are based on real announcements on a project level, collected by the EBA.

19 Gas for Climate (2022). Biomethane production potentials in the EU (Link)
20 Gas for Climate (2021). Market state and trends in renewable and low-carbon gases in Europe (Link)
21 IEA (2022). Scaling up biomethane in the European Union: Background paper (Link)

Figure 8
European bio-LNG production capacities in TWh and number of plants (EBA)



Biogenic CO_2 from biogas upgrading strengthens the decarbonisation value of biomethane

As discussed in the CO_2 markets section below, CO_2 can be used as a feedstock in many industries, and companies across different sectors are increasingly interested in biogenic CO_2 sourcing options. Biogenic CO_2 can replace fossil CO_2 and hereby, when captured, can drive the total CO_2 footprint of biogas plants further down. As presented in the 2021 MST Report, bioenergy with carbon capture and utilisation (BECCU) and storage (BECCS) are ways to achieve temporary or permanent negative emissions. EBA also explored the potential of biogenic CO_2 from the biogas industry as an opportunity to enhance sustainable carbon cycles and untap circularity of biogas production.[22]

There are two ways to capture biogenic CO_2 from biogas, (1) during the biomethane upgrading process where biogas is split into biomethane and CO_2 and (2) in biogas plants with combined heat and power (CHP) where biogenic CO_2 is captured from the flue gas during biogas combustion. The former has a higher concentration of CO_2, close to 100%, whereas flue gas CO_2 concentration ranges between 5-8 %. The captured biogenic CO_2, when combined with green hydrogen (H_2) can be used in the production of renewable synthetic fuels, such as synthetic kerosene, synthetic diesel and synthetic methane. Another alternative fuel is synthetic methanol, produced from the hydrogenation of biogenic CO_2. The theoretical EU potential of biogenic CO_2 from biogas ranges between 46 Mt in 2030 and 124 Mt in 2050, if 35 and 95 bcm of biogas and biomethane are to be produced in 2030 and 2050 respectively.[19]

Policy incentives to increase biomethane injection and catalyse biomethane demand

The scale up of biomethane requires significant action from the EU Member State (MS) level. As described in the Manual for National Biomethane Strategies, this ranges from a national vision, to preparing, enabling, and mobilising the right stakeholders to achieve national biomethane production targets.[23] Two examples of national policy to increase the production and injection of biomethane are highlighted below.

22 European Biogas Association (2022). Biogenic CO_2 from the biogas industry (Link)
23 Gas for Climate (2022). Manual for National Biomethane Strategies (Link)

Netherlands

In the Netherlands, the Dutch minister for Economic Affairs and Climate has announce a blending obligation of green gases into the gas system. This blending obligation of 20% by 2030 follows from the ambition to produce 2 bcm of green gas per year by the end of this decade, which is almost 10 times the current production. According to a letter to parliament, biomethane is an important building block for a sustainable and robust energy- feedstock- and agricultural system.[24] Suppliers of biomethane do not only have the possibility to physically buy and supply green gas but could also comply to the rule by buying certificates of producers.

This accelerated policy should be realised by intensifying the "Program Green Gas". Within this program, research will be done on how to increase production to above 2 bcm as soon as possible, but also how import of green gases can contribute to the energy transition.

France

The French authorities are expected to launch a call for gasification projects early 2024. The goal of this call will be to increase the production of biomethane plants and inject this in the gas network. At the same time, this will stimulate project and technology developers to further increase their efforts to commercial-size installations.

24 Dutch Ministry for Economic Affairs and Climate (2023). Kamerbrief over nadere uitwerking bijmengverplichting groen gas (Link)

2.2 Innovation & Technology

Topic 1: Gasification Technologies

- Examples are in France and the Netherlands
- SCW Systems, ENGIE
- Late 2020s – TRL 7/8
- All projects are up to 20 MW

In the 2021 version of this Market State and Trends report, hydrothermal gasification was noted to be on the verge of commercialisation and industrial scale will be reached by 2023-2025.

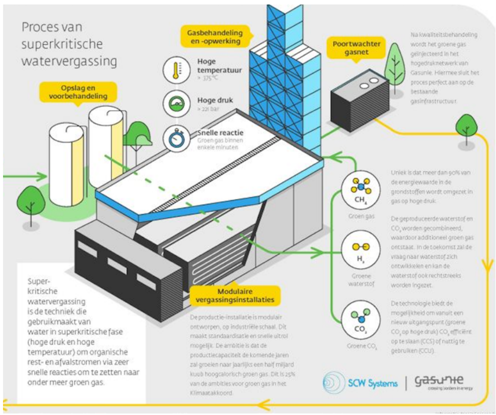
In this case study, we want to highlight the status of gasification technologies by looking into the status of **hydrothermal/supercritical water gasification and "pyro-gasification".**

Project examples

Hydrothermal/Supercritical Water Gasification (SCW Systems)

Can use an exceptionally broad range of both wet and dry waste from food industry and agriculture as feedstock, contributing to the processing of problematic waste streams. It uses water at high pressure and temperature (supercritical state) to convert feedstocks into green gas and other usable resources (hydrogen and CO_2) in a process with very fast reaction time. Large benefit is a high cycle conversion rate (90%). As there is no digestate and the waste is used for the next cycle, >99% conversion can be reached.

SCW Systems developed a modular design on an industrial scale (5MW units) that enable standardisation and fast roll-out. They are currently a 20 MW system right now and intend to scale by using more modules to build towards >100 MW systems in the coming years.



Pyrogasification – GAYA and Salamander projects (ENGIE)

Combination of pyrolysis and gasification. It is a mature technology, converting non-recyclable solid waste into renewable gases at high temperature in the absence of oxygen. In the GAYA plant, first syngas is produced which is further purified and transformed into biomethane though methanation. This plant demonstrated that the technology is ready to go to market.

ENGIE plans to build its first industrial unit in Le Havre, France. Starting in 2026, the Salamandre project will turn 70,000 tons of non-recyclable waste per year into 150 GWh of biomethane and 45 GWh of renewable heat to meet urban and industrial needs. This project will further drive down costs by standardizing equipment and increasing competition between suppliers. This will enable the further roll-out of the technology

Topic 2: Feedstock pre-treatment

Netherlands

Various technology providers

Scaling up technology towards the end of the 2020s

Scale-up in is possible with higher pressures towards 100 MWs

To accelerate the scale-up of biomethane towards the EU target of 35 bcm, it will be required to tap into several types of feedstocks. Some feedstock types, especially waste streams, are challenging to use for the production of biomethane. They do not have a consistent homogeneous composition, resulting in problems with operation of gasification installations and a fluctuating gas quality output.

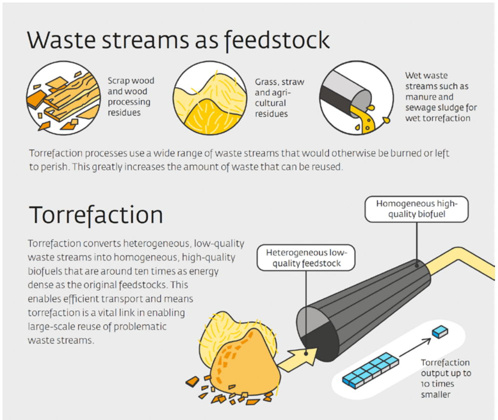
This case study focuses on the torrefaction of feedstock, to create homogeneous pallets that can be used to produce biomethane in gasification installations.

Torrefaction of waste streams (TRL 6/7)

Torrefaction processes use a wide range of waste streams that otherwise would be burned or left to perish. It helps to increase the amount of waste that can be reused. The process converts heterogeneous, low-quality waste streams into homogeneous, high-quality biofuels that are around 10x as anergy dense as the original feedstocks. This enables efficient transport, and this can be a vital link in enabling large-scale reuse of problematic waste streams, tapping into new types of feedstocks. After torrefaction, these pallets can be gasified, producing biomethane or hydrogen, together with biogenic CO_2.

Torrgas is one of the companies that is working on this technology, converting all biogenic carbon into valuable products. They are currently operating a demo plant in the Netherlands and intend to scale up towards 100 MW. For this, it will be key to feed this into the high-pressure TSO network, and source the biomass locally.

Example companies: Torrgas, TorrCoal, Blackwood Technology



3. Hydrogen trends

Key takeaways

Reaching the 10 Mt of domestic renewable hydrogen (set by REPowerEU Plan) requires almost 100 GW of installed electrolyser capacity by 2030 but projections lag behind target. The high interest rates and inflation observed since 2022 add challenges as leveraging debt is more expensive resulting in increased overall project costs. The IEA forecasts that economies of scale and mass production can decrease overall capital costs. In turn, the EU Green Deal policy and regulatory architecture has introduced renewable hydrogen consumption quotas that should trigger more demand and provide certainty for investments.

The rapid development of an interconnected European hydrogen infrastructure is fundamental to enable a competitive, liquid, pan-European hydrogen market. In line with the European Hydrogen Backbone initiative, several countries are developing multiple (cross-border) infrastructure projects to offer strategic interconnections between supply centres and end-consumers. These projects can also benefit from an accelerated permit granting process and an improved regulatory treatment.

Offshore hydrogen production projects with transport infrastructure to shore can facilitate the integration of increasing renewable energy capacity in the energy system. Transmission cost for hydrogen is lower than for electricity and offshore pipelines enable the aggregation of offshore hydrogen production from multiple wind farms. Several companies are already working on pilot projects and are bringing forward a systemic vision.

3.1 Markets

3.1.1 Supply

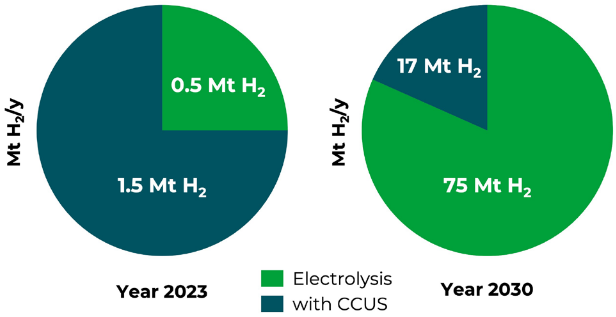
Hydrogen project pipeline and electrolysis manufacturing capacity continue to grow

The Global Hydrogen Review 2023 by the International Energy Agency (IEA) revealed that global hydrogen production reached almost 95 Mt in 2022, an increase of 3% compared to 2021. However, hydrogen produced from unabated fossil fuels accounted for the majority of such increase. In 2021, although only 35 kt of hydrogen came from electrolysis, this amount represents an increase of almost 20% compared to 2020 figures, reflecting an increased deployment of electrolysers. Low-carbon hydrogen production in 2022 was less than 1 Mt (0.7% of global production), very similar to 2021, with its majority coming from fossil fuels with CCUS.[25]

Figure 9 shows the nominal hydrogen production capacity (Mt/y) of projects operational globally, as well as in concept, planning or implementation stage.[26] In 2023, over than 75% of the total low-carbon hydrogen production capacity stems from fossil assets with CCUS. By 2030, the IEA expects that this trend will revert and hydrogen production with electrolysers will prevail over alternatives using CCUS.

25 IEA (2023). Global Hydrogen Review (Link)
26 This represents the theoretical hydrogen production if production units were to run at full load.

Figure 9
Low-carbon hydrogen production by technology route, World Markets, 2023 vs. 2030[27]

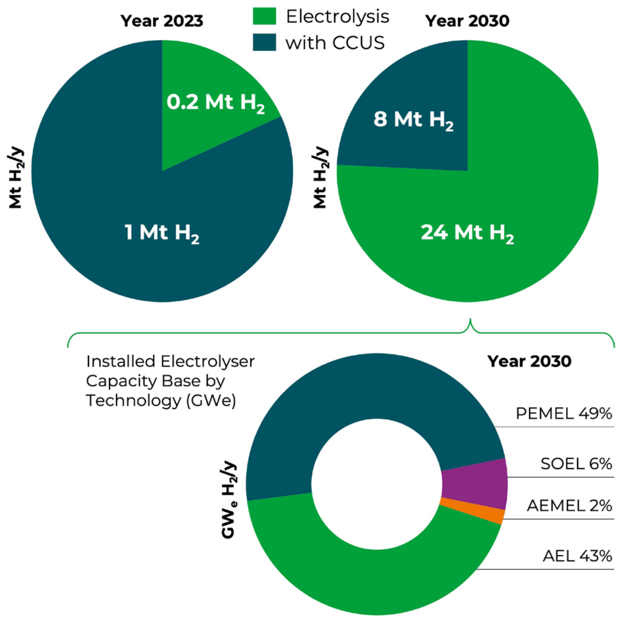


The hydrogen project pipeline continues to grow rapidly around the world. In 2022, the IEA registered that more than 3.8 GW of electrolyser projects have reached Final Investment Decision (FID) or started construction.[28] The highlight is NEOM Green Hydrogen, which is the biggest project that started construction with a planned 2.2 GW of electrolyser installed capacity. Once commissioned, the NEOM project could produce 600 tonnes per day of green hydrogen and up to 1.2 Mt/y of green ammonia.[29]

Despite large projects announced in the MENA region, Europe is amongst the front runners in announced electrolytic hydrogen production projects.[30] As shown in Figure 10, based on the IEA Hydrogen Production and Infrastructure Projects Database (2023), electrolytic hydrogen production in Europe could reach close to 24 Mt of hydrogen by 2030. Hydrogen production from fossil fuels in combination with CCUS (low-carbon hydrogen) in Europe could account for almost 8 Mt of hydrogen by 2030, with projects announced mostly in the Netherlands and the United Kingdom.[31] Proton exchange membrane (PEMEL) and alkaline (AEL) electrolyser technologies will lead the market in 2030 in Europe, followed by solid oxide (SOEL) and a small portion for anion exchange membrane (AEMEL) (Figure 10).[32]

For example, in July 2022, Shell reached FID regarding the Holland Hydrogen I project, which will be located in the port of Rotterdam, sourced by an offshore wind farm (partly owned by Shell). With its planned 200 MW electrolyser, the project is set to become the largest renewable hydrogen plant in Europe as of 2025. The project could produce up to 60,000 kilograms of renewable hydrogen per day.[33]

Figure 10
Hydrogen Production (Mt/y) by Production Route, Europe: 2023 vs. 2030 and Installed Electrolyser Capacity Base by Technology in 2030 (GW_e).[34]



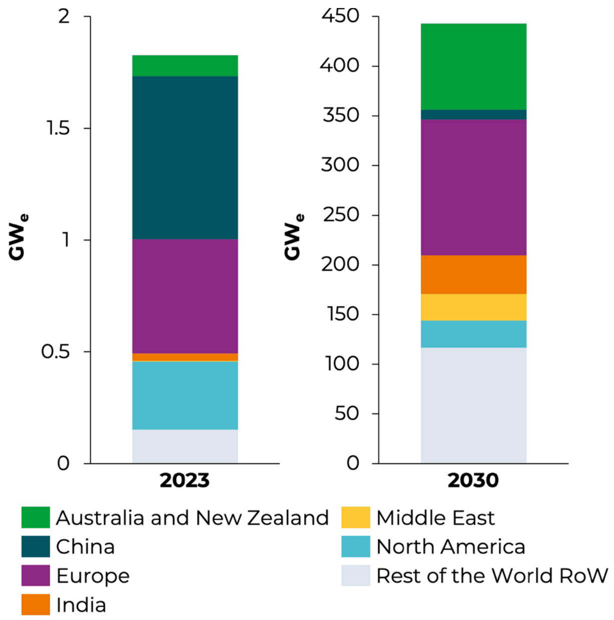
According to Guidehouse Insights, Europe is anticipated to lead on installed electrolyser capacity, surpassing the Asia Pacific region by 2025, to reach more than 43.8 GW_e in 2032.

27 Own elaboration based on IEA (2023). Hydrogen Production and Infrastructure Projects Database (Last updated October 2023) (Link)
28 IEA (2023). Global Hydrogen Review 2023 (Link)
29 Acwa Power (2022). Neom Green Hydrogen Project (Link) and Hydrogen Insight (2023). Neom becomes first gigawatt-scale green hydrogen project to secure funding, with $8.5bn lined up (Link)
30 IEA (2023). Hydrogen Production and Infrastructure Projects Database (Last updated October 2023) (Link)
31 IEA (2022). Global Hydrogen Review 2022 (Link)
32 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook (Link). The electrolyser technologies are also referred to as ALK (instead of AEL), PEM (PEMEL), SOEC (SOEL) and AEM (AEMEL).
33 Shell (2022). Shell to start building Europe's largest renewable hydrogen plant (Link)
34 Own elaboration on IEA Hydrogen Production and Infrastructure Projects Database (Last updated October 2023) (Link) and Guidehouse Insights (2023) Electrolyzer Supply and Demand Outlook (Link).

New capacity additions have so far been slow to materialize due to policy and regulatory uncertainties. Hence, the study assumes that impediments to project financing and construction in the EU will start to ease to allow for a faster scale-up.[35] In this regard, Germany has announced ambitious plans to cover its expected demand. According to the updated National Hydrogen Strategy, the German government introduced the target of 10 GW of domestic electrolyser capacity by 2030.[36]

In 2022, around 80 MW of electrolyser capacity were added in the EU, which represents more than twice the capacity that was installed in 2021.[37] Besides, based on the IEA Hydrogen Production Database, the estimated installed capacity in the EU in 2023 reached 266 MW_e. The electrolyser manufacturing capacity is expanding as it becomes clear that new projects will be realized in the coming years to match both policy and private sector goals. The IEA 2023 database shows that by 2030 a total electrolysis capacity of more than 400 GW_e[38] could be reached globally (Figure 11). Such an installed capacity could translate into an annual production of renewable hydrogen of more than 24 Mt by 2030.[39] Figure 11 also shows the current electrolyser installed capacity by region in 2023. Regarding global markets, the introduction of the Inflation Reduction Act (IRA) in the United States of America (US) will have a particular impact as it provides solid support to renewable and low-carbon hydrogen. According to the US Department of Energy, the national electrolyser capacity shall increase from 0.17 GW today to up to 1,000 GW in 2050.[40]

Figure 11
Installed Electrolyser Capacity Base by Region, World Markets: 2023 vs. 2030[41]



EU target of 10 Mt of local production faces a large gap

The European Commission's REPowerEU Plan introduced the target of 20 Mt of renewable and low-carbon hydrogen in 2030, of which 10 Mt should come from domestic production and 10 Mt from imports.[42] In May 2022, the Hydrogen Alliance issued a joint declaration to express that meeting the domestic production of 10 Mt of hydrogen requires the EU to significantly upscale its electrolyser manufacturing capacities. It would require an installed electrolyser capacity of 90 - 100 GW[43,44] In 2022, the capacity of electrolyser manufacturers in Europe was estimated at 1.75 GW per year, which shows the large gap to be filled and the need for a considerable growth. The outlooks towards 2030 are conflicting.

35 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook (Link)
36 Clean Energy Wire (2023). Germany aims to accelerate hydrogen market ramp-up with strategy update (Link)
37 IEA (2023) Electrolysers (last updated July 2023) (Link)
38 The IEA clarifies that the global installed electrolyser capacity could reach between 175 GW to 420 GW when projects at early stages of development are also taken into consideration. Early-stage projects are, for example, projects for which only a co-operation agreement among stakeholders has been announced.
39 IEA (2022). Global Hydrogen Review 2022 (Link) and IEA (2023). Tracking Clean Energy Progress 2023 (Link)
40 U.S. Department of Energy (2022). Water Electrolyzers and Fuel Cells Supply Chain Deep Dive Assessment (Link)
41 IEA (2023). Hydrogen Production and Infrastructure Projects Database (Last updated October 2023) (Link)
42 European Commission (2022). REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition (Link)
43 According to the Hydrogen Alliance joint declaration, these figures are measured in terms of hydrogen output; up to 140 GM if measured in terms of electricity input. This assuming an average electrolyser utilisation factor of 43% and electrolyser efficiency of 70% (Link)
44 European Clean Hydrogen Alliance (2022). European Electrolyser Summit, Joint Declaration (Link)

On the one side, according to the IEA, if the announced projects in the EU are realized, the output would be 95 GW by 2030, which is almost aligned with the forecasted 100 GW. This estimation comes with the assumption that European manufacturers do not export their electrolysers outside Europe.[45] On the other side, data from BloombergNEF and RaboResearch show that the total planned installed capacity would reach 43 GW by 2030, which evidences a large gap with the 100 GW needed to meet the EU policy goals.[46]

Besides, a bottom-up study by the European Hydrogen Backbone (EHB) prior to the publication of the REPowerEU identified 14.7 Mt of demand by 2030, representing tangible and achievable projections based on national targets, market developments, and announced projects.[47]

Figure 12 shows the announced cumulative electrolyser installed capacity in Europe by 2030 (GW).

Figure 12
Announced cumulative electrolyser installed capacity in GW by 2030 in Europe[48]

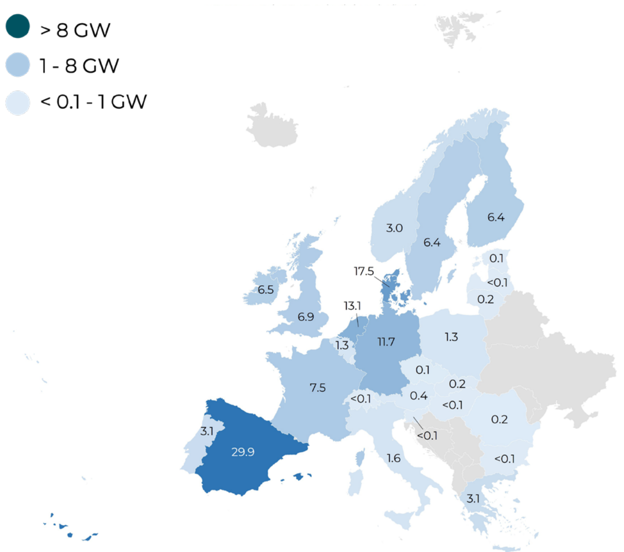
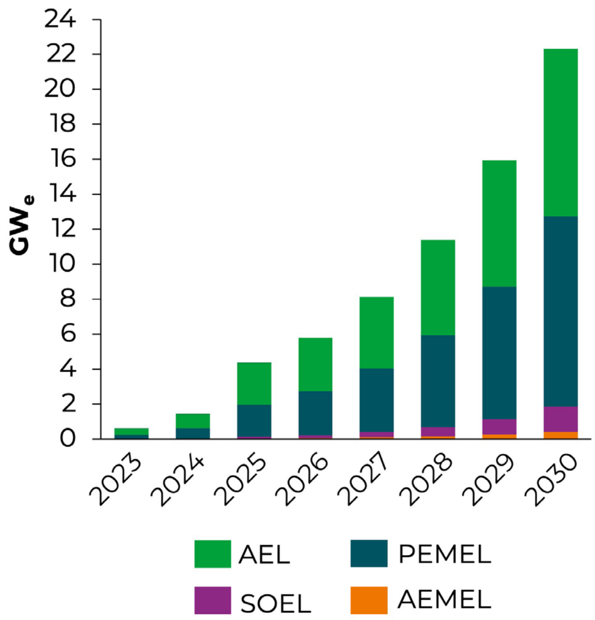


Figure 13
Installed electrolyser capacity by Technology in Europe between 2023-2030[49]



A forecast from Guidehouse Insight anticipates that cumulative electrolyser capacity additions in Europe will rise to 22.3 GW_e by 2030 (Figure 13). Although Europe remains a global leader in hydrogen technology manufacturing and benefits from a robust project pipeline, there are barriers and uncertainties that reduce the speed of market developments. Therefore, large-scale projects at advanced development stages in the EU have tended to be captive hydrogen plants supported by large industrial consumers.[50]

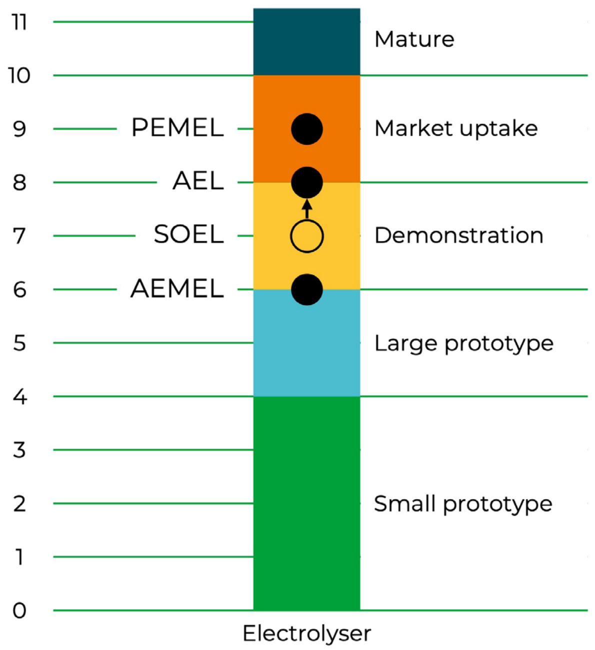
Besides electrolyser production capacity, a faster deployment of renewable energy projects is also important to ensure RES additionality and reduce emissions. Flexibility and integration strategies are becoming increasingly important as the energy system will need to accommodate larger RES capacities.

45 IEA (2022). Global Hydrogen Review 2022 (Link)
46 Rabobank (2023). Spain, Denmark and the Netherlands To Be The EU Hydrogen Hot Spots (Link)
47 European Hydrogen Backbone (2023). Implementation roadmap – Cross border projects and costs updates (Link)
48 IEA (2023). Hydrogen Production and Infrastructure Projects Database (Last updated October 2023) (Link)
49 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook (Link)
50 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook (Link)

AEL and PEMEL electrolyser technologies will continue to dominate the market, but SOEL and AEMEL are increasing their technology readiness

As presented in the 2021 report, the four main electrolyser technologies are AEL, PEMEL, SOEL, and AEMEL. As shown in Figure 14, the former two are the most advanced technologies, whereas SOEL and AEMEL are still maturing in the market. In particular, SOEL technology has improved its readiness level in the last 2 years through an accelerated approximation to commercialization and industry-scale projects under construction.[51]

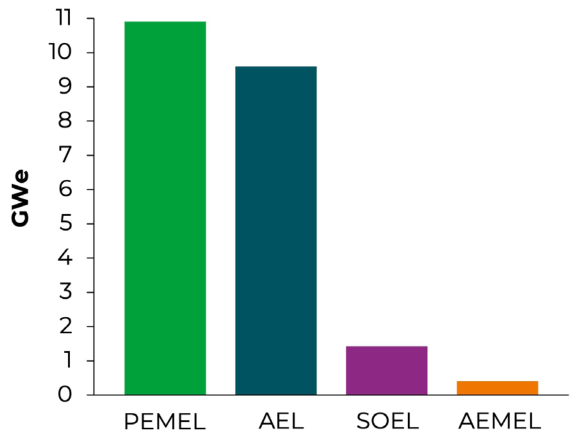
Figure 14
Technology readiness levels of electrolyser technologies. Source: IEA (2023)



The electrolyser manufacturing capacity of these technologies is expanding to meet the expected growing demand set by the market and the increased policy ambitions.

In Europe, Guidehouse Insights forecasts that PEMEL is set to grow at a faster pace than AEL, reaching 10.9 GW_e of cumulative capacity by 2030. AEL is forecast to reach 9.6 GW_e of cumulative capacity by the same year. SOEL and AEMEL exhibit especially strong growth over the latter half of the forecast period (2023-2032), reaching 1.4 GW_e and 0.4 GW_e of cumulative capacity, respectively, by 2030.[52]

Figure 15
Installed Electrolyser Capacity Base by Technology in 2030 in Europe (GWe).[53]



On the one side, AEMEL electrolysers have been mainly deployed in demonstration projects and their production is at an early stage of development with a small-scale production. The leading manufacturer Enapter announced plans to build manufacturing capacities of 280 MW by 2023. On the other side, SOEL is quickly approaching commercialisation. For example, by 2025 Topsoe expects to operate an industrial-scale 500 MW/y manufacturing facility in Denmark. Besides, a 2.6 MW SOEL electrolyser was installed in a Neste refinery in the Netherlands in April 2023.[54]

Globally, while AEL electrolysers represented 60% of the installed capacity by the end of 2022, it is expected that PEMEL, which accounted for 30% in 2022, will considerably increase its market share in the upcoming years. PEMEL manufacturing capacity could reach almost one-quarter of the global capacity, however, AEL would still account for the largest share at 54%.[55]

51 IEA (2023) Electrolysers (last updated July 2023) (Link)
52 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook (Link)
53 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook (Link)
54 IEA (2023) Electrolysers (last updated July 2023) (Link)
55 IEA (2023). Global Hydrogen Review 2023 (Link)

System integration of electrolysers with RES is gaining relevance

In countries where hydrogen producers can be expected to source some of their renewable electricity demand from the overall power grid — rather than from dedicated co-located renewable energy plants — system integration becomes increasingly important. While grid connected electrolysers are primarily regarded as load, they also offer many synergies and benefits for the power system.

As of now, regulation governing interactions between grid-connected electrolysers and the power system is still largely lacking. This concerns both the sourcing of power to produce renewable hydrogen and the ability of electrolysers to participate in markets for ancillary services and interact with markets for system services. Whether hydrogen projects will be able to provide system services, depends first and foremost on regulatory aspects, e.g., whether electrolysers or storage assets can participate in markets for balancing services. Moreover, the characteristics of the power system itself determine whether there is sufficient capacity for electrolysers to be connected to the grid in the first place.

Flexible electrolyser operation can provide a range of power system services by:[56]

- adjusting output in response to system needs to provide balancing services,
- alleviating grid congestions in transmission and distribution networks,
- reducing renewables curtailment,
- diminishing peak load in the power grid e.g., from industry or buildings,
- supporting peak generation if combined with hydrogen storage and re-electrification options, and
- feeding into diurnal or seasonal hydrogen reserves for back-up power generation.

The concrete project set-up, technical parameters and regulatory requirements regarding electricity sourcing determine how electrolyser operation increases power system flexibility needs or whether it can provide benefits for system integration.

Technical: Different electrolysis technologies have different start-up times and ramp-up speeds. PEMEL electrolysers can react very quickly and can even increase their load range above 100% for a limited amount of time if necessary.[57] AEL electrolysers are generally also able to provide ancillary services, e.g., balancing services or congestion management products. SOELs are considered less flexible based on the limited practical experience available. Given their high efficiency and rather high CAPEX they might be less suited for ancillary service provision but rather for use cases with constant power supply.

Project set-up and economics: In absence of liquid hydrogen markets, projects will most likely require fixed volume offtake contracts. This gives less room for flexibly adjusting output in response to potential price signals at markets for ancillary services. To achieve high electrolyser full load hours and reduce levelized cost of hydrogen (LCOH), projects may be designed with renewable energy overcapacity relative to electrolyser size or be connected to battery storage. Such project set-ups are less dependent on sourcing grid electricity and could potentially act as providers of flexibility, if permitted by the regulator.

Electricity sourcing regulation: The current EU sustainability criteria for Renewable Fuel of Non-Biological Origin (RFNBO) require simultaneity of renewable hydrogen production and renewable energy generation on an hourly basis from 2030 onward. A key objective of this regulation is to avoid increasing power sector emissions by higher grey electricity output. More flexible operation (less granular temporal correlation) can however

56 IRENA (2023). Innovation landscape for smart electrification (Link)
57 ENTSO-E (2022). Potential of P2H_2 technologies to provide system services (Link)

also bring reductions in LCOH and overall power sector emissions as electrolysers can react to power market signals more flexibly.[58]

Given that electrolysers have an impact on the power system and at the same time can offer services, it is vital to assess the system implications and possible synergies. The particular synergies and opportunities should be reflected in regulations, in the access to markets for balancing services and also electrolysers operational patterns (including grid power sourcing).

In the EU, some companies are already implementing projects that are either innovative or follow an integrative view across the entire value chain. On the one side, some producers adopt an innovative production process where the electrolyser is directly installed at the wind or solar source. For instance, HYGRO Direct Hydrogen Production allows the company to offer a more efficient hydrogen production by skipping DC to AC and AC to DC power electronics conversions.[59] The AquaVentus project is also testing wind offshore sites coupled with electrolysers. After production, the project plans to use hydrogen pipelines that are more cost-effective that high-voltage direct current (HVDC) transmission systems that would otherwise need to be built.[60]

On the other side, some projects adopt a systemic vision, such as the HyDeal Ambition, launched in 2020 by 30 companies (upstream, midstream, downstream), which has designed an integrated industrial system leveraging Iberian solar power to deliver hydrogen to off takers in industry, energy and mobility. It aims to reach a potential of 67 GW of electrolysers and 3.6 Mt per year of hydrogen.[61]

Cost of green hydrogen production in Europe has increased

The global economy has been negatively impacted in 2022 by inflation, the rise of interest rates and the consequent increased costs of capital. As a result, leveraging debt for large projects that are CAPEX intensive has become more difficult, risky, and expensive. Hydrogen projects have also been affected by higher labour costs and raw materials supply chain issues, all of which caused many projects to revise their costs upwards. This revision created delays and can lead to cancellations of projects. The impact of higher interest rates is even stronger in more risky projects that involve innovative solutions, such as hydrogen production integrated with offshore wind plants, as the risk appetite of investors decreases considerably during economic turmoil.

As a result, previous estimates projecting global renewable hydrogen production costs in 2030 as low as €1.2 to €4.15 per kilogram (kg) have now been revised upwards substantially to €5 to €8/kg for central Europe, given revised electricity price assumptions.[62,63] Current production costs have already been impacted by inflation and are higher than previously expected. In October, the monthly average hydrogen price in the Netherlands ranged between €7.1/kg and €8.2/kg.[64]

Support measures can help to accelerate the roll-out of hydrogen production projects. The EU Commission has launched a pilot auction for the production of renewable hydrogen under the Innovation Fund (European Hydrogen Bank). Selected projects can benefit from a fixed premium (€/kg of verified and certified RFNBO hydrogen) on top of the market price. The support is offered for a period of up to 10 years. The total budget for the first auction round amounts to €800 million.[65]

58 Ruhnau, O. and Schiele, J. (2023). Flexible green hydrogen: The effect of relaxing simultaneity requirements on project design, economics, and power sector emissions (Link)
59 Interview conducted with HYGRO, October 2023.
60 Interview conducted with AquaVentus, October 2023.
61 Interview with HyDeal, October 2023.
62 IEA (2022). Global Hydrogen Review 2022. (Link)
63 BCG (2023). Turning the European green hydrogen dream into reality: a call to action. (Link)
64 S&P Global (2023). Platts hydrogen price wall. (Link)
65 European Commission (2023). Innovation Fund, Competitive bidding. (Link)

MS can also provide support schemes to hydrogen producers. For example, the German hydrogen strategy aims to incentivize early movers in the industrial sector providing investment grants and Carbon Contracts for Difference to close the gap for the higher cost of renewable hydrogen production compared with conventional processes.[66]

In 2022, the capital cost for an installed electrolyser ranged globally between €1590/kW for AEL and €1870/kW for PEMEL, which represents a year-on-year increase of about 9% compared to the capital costs registered in 2021.[67,68] In Europe, the current average levelized cost of renewable hydrogen is between €4.2/kg and €5.6/kg.[69]

However, despite the increased costs triggered by inflation and higher interest rates that particularly impacted the cost of capital (loan interest), the IEA expects that mass production and economies of scale could help decreasing capital costs of electrolyser deployment, reaching €673 to €757/kW by 2030. IEA also forecasts that if electrolyser projects in the pipeline are completed and the planned scaling up in manufacturing capacities takes place, costs could fall by around 70% by 2030 compared with today. The IEA assumes a learning rate of 18% for the electrolyser stack, representing about half of the system cost, and between 5-12% for the other components and the balance of plant.[70]

Putting a price on carbon can improve competitiveness of low-carbon hydrogen against grey hydrogen

The production of low-carbon hydrogen (by using carbon capture) represents an attractive option for regions with access to low-cost natural gas or with limited potential for renewable energy technologies. In the EU, low-carbon hydrogen has the advantage of paying less carbon tax imposed through the EU Emission Trading System since its production emits fewer carbon emissions compared to grey hydrogen. This competitive advantage can continue to increase as the carbon price has been increasing and is expected to increase even further.

Local production of low-carbon hydrogen in Europe could reach more than 3 Mt low-carbon hydrogen by 2030, with projects announced in the United Kingdom, the Netherlands and Norway.[71]

Producers of low-carbon hydrogen in the US can potentially benefit from IRA support in the form of either a clean hydrogen tax credit (between $0.60/kg and $3/kg of clean hydrogen produced) or alternatively from the CCUS tax credits ($85/Mt CO_2 for point source capture).[72] On the contrary, the EU has not passed any direct support scheme or fiscal benefits for low-carbon hydrogen production.

3.1.2 Infrastructure and storage

Developing energy infrastructure (storage and transport) involves large investments, long lead times (permitting, cross-border agreements) and risks. To enable the hydrogen market, the world needs new pipelines, repurposing of existing gas pipelines and storage solutions.

Europe needs a rapid scale-up of domestic transport and storage infrastructure

To meet the ambitious EU climate and renewable hydrogen targets the rapid development of an interconnected and functioning European hydrogen infrastructure will be needed. The development of such infrastructure is also key to enable a competitive, liquid, pan-European renewable and low-carbon hydrogen market. Designing adequate hydrogen corridors will be challenging as it

66 German Federal Ministry for Economic Affairs and Climate Action (BMWK). (2023). National Hydrogen Strategy. (Link)
67 IEA (2023). Global Hydrogen Review 2023. (Link)
68 In all conversions and comparison across the document, an exchange rate of 1 US Dollar = 0,94 Euro is assumed.
69 IRENA (2023). Innovation landscape for smart electrification. (Link)
70 IEA (2022). Promising signs in electrolyser manufacturing add to growing momentum for low-emissions hydrogen (Link)
71 IEA (2023). Global Hydrogen Review 2023. (Link)
72 S&P Global (2023). Blue hydrogen: The future of certified gas? (Link)

involves multiple countries and stakeholders with competing interests. It will also require the adoption of new regulation to govern the infrastructure and its operation in the emerging market.

The EHB, an initiative by a group of European TSOs, has set out a vision for an integrated pan-European backbone. The strategy focuses on offering an economical connection between regions of hydrogen supply and the hydrogen consumers in central Europe via cross-border pipeline corridors. EHB has developed hydrogen maps reflecting important elements such as salt caverns, aquifers, repurposed and new pipelines, gas-import terminals, etc.[73] Several countries are already developing multiple (cross-border) infrastructure projects, for example:[74]

- The AquaDuctus project (GASCADE, Fluxys) will develop an offshore hydrogen pipeline to connect a large-scale offshore hydrogen wind farm site, located 150 km northwest of the island of Heligoland. The pipeline will transport renewable hydrogen to Germany. The pipeline will also offer interconnection to other offshore hydrogen pipelines in Denmark, Netherlands, the UK, Norway, among others. The project is in the feasibility phase.

- In the Netherlands, the project Hydrogen Networks Netherlands reached a Final Investment Decision (FID) (Gasunie). The project objective is to create and open access non-discriminatory national and cross-border network for connection with large-scale hydrogen storage in northeast Netherlands. The project is expected to benefit consumers in the Netherlands, Germany, and Belgium. From 2030 onwards, the project will have a capacity between 10 GW and 15 GW.

- The Spanish Hydrogen Backbone (Enagás) aims to connect the industrial clusters located in the Mediterranean coast and northern Spain. The network will enable the connection of production centres in Spain's rich renewable sources areas. By 2030, connections with France (Barcelona-Marseille) and Portugal are planned.

- Germany will play a central role as it is part of all EHB identified corridors. The German TSOs together with the Federal Ministry of Economic Affairs and Climate Action (BMWK) and FNB Gas e.V. are working closely to develop the Hydrogen Core Network which is expected to be about 11,200 km.

As of September 2023, two sets of hydrogen Important Projects of Common European Interest (IPCEIs) have received state aid approval by the EU Commission: Hy2Tech (up to €5.4 billion in public funding) and Hy2Use (up to €5.2 billion in public funding). These two IPCEIs will support a broad set of research and innovation activities, construction of relevant infrastructure in the hydrogen value chain, such as large-scale electrolysers, transport infrastructure, as well as the development of innovative technologies for the integration of hydrogen into industrial processes.[75] Further hydrogen IPCEIs are expected in late 2023.

The Trans-European Networks for Energy Regulation (TEN-E) sets three infrastructure gas priority corridors which are planned to become a core part of the EU hydrogen network with hydrogen transmission and storage infrastructure or repurposed from natural gas:[76]

- Hydrogen interconnections in Western Europe (HI West): Belgium, Czechia, Denmark, Germany, Ireland, Spain, France, Italy, Luxembourg, Malta, Netherlands, Austria and Portugal.

73 European Hydrogen Backbone. EHB Maps. (Link)
74 European Hydrogen Backbone (2023). Implementation roadmap – Cross border projects and costs updates. (Link)
75 IPCEI Hydrogen (2023). (Link)
76 European Commission (2023). Projects of Common Interest – Selection process. (Link)

- Hydrogen interconnections in Central Eastern and South-eastern Europe (HI East): Bulgaria, Czechia, Germany, Greece, Croatia, Italy, Cyprus, Hungary, Austria, Poland, Romania, Slovenia and Slovakia.

- Baltic Energy Market Interconnection Plan in hydrogen (BEMIP Hydrogen): Denmark, Germany, Estonia, Latvia, Lithuania, Poland, Finland and Sweden.

Besides, when two or more MS intend to develop an infrastructure project to link their energy systems and contribute to the EU's energy goals, the project can become Project of Common Interest (PCI) status and can benefit from an accelerated permit granting process, improved regulatory treatment, and become eligible for financial support from the Connecting Europe Facility (CEF). In addition, the TEN-E also contemplates the case of Projects of Mutual Interest (PMI), which consist of energy infrastructure projects promoted by the EU with third countries and extend to these projects' similar benefits as PCIs.

In November 2023, the EU Commission published the list of PCIs and PMIs that are in line with the European Green Deal and under the revised TEN-E regulation.[77,78] Of the 166 selected PCIs and PMIs, 65 are hydrogen and electrolyser projects. The list includes hydrogen projects in Western Europe (HI West), in Central Eastern and South Eastern Europe (HI East), and in Baltic Energy Market Interconnection Plan in Hydrogen (BEMIP Hydrogen). Examples in the HI West corridor include PCIs such as the hydrogen interconnector Portugal-Spain, the France-Germany cross-border hydrogen valleys, or the Hystock H_2 storage project in the Netherlands. An offshore hydrogen pipeline Norway – Germany (CHE pipeline) is listed as a PMI in the HI West corridor.[79]

Member States individually are also announcing plans and advancing regulation regarding infrastructure. On the one side, as part of the updated German National Hydrogen Strategy, Germany plans to reinforce the needed infrastructure and wants to build 1,800 km of converted and new hydrogen pipelines by 2027/2028.[80] Through connections with other MS, 4,500 km could be added across Europe.[81] On the other side, Belgium has an extensive hydrogen network connecting to France and the Netherlands (600 km) and in 2023 adopted legislation on the transport of hydrogen by pipelines being the first Member State (MS) to pass this type of regulation. According to the new law, a Hydrogen Network Operator (HNO) shall be appointed and will operate for a period of 20 years. The HNO has the competence to, among others, ensure a non-discriminatory third-party access to the network, publish a network development plan every two years, and guarantee hydrogen quality standards are met.[82] The law also introduces an independent regulator (Commission for Electricity and Gas Regulation) who is responsible for the implementation of the law and also for monitoring compliance.[83]

The development of hydrogen storage technologies is a very relevant part of the hydrogen economy to allow a more liquid market and international trading. Storage capacity can also enable balancing mechanisms for the power system, which creates additional market opportunities for hydrogen producers.

Besides, as the production of renewable hydrogen may face intermittency (due to variable renewable electricity sourcing), off takers of green hydrogen will also benefit from storage solutions to ensure a reliable and consistent supply. Overall, hydrogen storage can contribute to a more solid security

77 European Commission (2023). Press corner. (Link)
78 The European Parliament and the Council have 2 months to review the list and accept or reject it.
79 European Commission (2023). Annex on the first Union list of Projects of Common and Mutual Interest. (Link).
80 Clean Energy Wire (2023). Germany's National Hydrogen Strategy. (Link)
81 German Federal Government (2023). National Hydrogen Strategy – Energy from climate-friendly gas. (Link).
82 ICIS (2023). Belgium passes new hydrogen transmission law. (Link)
83 PwC Legal (2023). Update: Belgian Hydrogen Transportation Law is out and applications are now open. (Link)

of supply. According to a report by LCPDelta, the hydrogen storage landscape in 2030 will be composed of a mix between salt caverns, depleted gas fields, and some new-built lined rock caverns.[84]

It is worth mentioning some industry-scale storage options and research facilities in Europe. In April 2023, the world's first hydrogen storage facility in an underground porous reservoir started operation (RAG Austria AG).[85] Electrolytic hydrogen is produced from solar energy and stored in pure form in an underground natural gas reservoir in Gampern, Austria. Salt caverns are also an interesting storage option already in use for industrial-scale storage in the United States and the United Kingdom. In Germany, the research project HyCavMobil is examining how hydrogen can be stored in salt caverns to be later used for fuel cell mobility.[86] There are other research initiatives focused on the development of other types of underground storage sites, such as depleted gas fields, aquifers and lined hard rock caverns.[87]

Moreover, linepack storage constitutes another aspect to highlight as it provides flexibility in the operation of the pipelines. When the linepack storage services are complemented with the use of geological storage, the system can absorb fluctuations between production and consumption, adapting to the requirements of the final consumer.

Import infrastructure for hydrogen and its derivatives also needs to be developed

Given that the demand of hydrogen is forecasted to grow, local production will not be enough in many countries such as Germany. Therefore, imports of hydrogen will be a fundamental part of the hydrogen economy. For supply centres within the EU or in neighbouring countries, new or repurposed pipelines could be used. If they meet certain requirements, projects dealing with pipelines can qualify as IPCEI, PCI, or PMI as described above.

Besides, as the transportation of pure hydrogen over long distances (e.g. over 2,500 km) faces efficiency and practical challenges, hydrogen derivatives allow for a simpler and more effective transportation. The main hydrogen derivatives are ammonia, liquid organic hydrogen carriers (LOHC) and synthetic fuels.

However, to enable the needed exports and imports, dedicated infrastructure is needed. Regarding the trade of ammonia and LOHC, ports will need to be equipped with special infrastructure such as converters from hydrogen into carriers and vice versa.[88] IEA shows that meeting the forecasted ammonia global demand for 2030 would require tripling the existing trade infrastructure. Some countries that will start to play a more important role in ammonia trade will also require other equipment such as storage tanks and deep-water ports, which demand time and large investments.[89]

EHB has analysed different corridors that could enable hydrogen imports. Within the North Africa and Southern Europe Corridor, the Italian Hydrogen Backbone could enable the transport of hydrogen produced in North Africa to European end-users and the SoutH$_2$ Corridor project aims to connect North Africa with Italy, Austria, and Germany. Several other projects are focusing on the Southwest Europe and Nort Africa corridor, such as the Portuguese and the Spanish Hydrogen Backbones.[90]

84 LCPDelta (2023). Unlocking Hydrogen Storage Vaults: Europe's long-duration hydrogen storage outlook to 2030. (Link)
85 RAG (2023). Underground Sun Storage: World's first geological hydrogen storage facility goes into operation. (Link)
86 DLR – Institute of Networked Energy Systems. Research Project HyCavMobil. (Link)
87 IEA (2023) Hydrogen (last updated July 2023). (Link)
88 Synthetic fuels such as methanol or sustainable aviation fuels (SAF) are not converted to hydrogen and adequate infrastructure already exists.
89 IEA (2023). Global Hydrogen Review 2023. (Link)
90 European Hydrogen Backbone (2023). Implementation roadmap – Cross border projects and costs updates. (Link)

3.1.3 Demand

EU policy can trigger more renewable hydrogen demand but there is a large gap to fill

The recent EU Renewable Energy Directive (RED III) has introduced renewable hydrogen consumption quotas that should trigger more demand from end-users. Targets and quotas, such as in the industry sector, create investment certainty as consumers will need to acquire new technology or adapt current technology to renewable hydrogen or derivatives.

Despite new policies and ambitions, the use of green and low-carbon hydrogen still represents only a minor share in total consumption. In 2022, low-carbon hydrogen accounted only for less than 1% of global hydrogen production and use.[91] Hence, there is a large gap to fill if climate goals are to be met.

Next to established applications, new applications of hydrogen are on the rise

Hydrogen is used broadly in different industries for traditional applications such as for ammonia and methanol production, and for Direct Reduced Iron (DRI) in the iron and steel subsector. Besides these traditional applications, the use of hydrogen in innovative uses such as in transport, power generation, as a reducing agent in 100%-hydrogen DRI, etc, has potential to grow. To exploit the potential of renewable hydrogen in innovative application, certain barriers should be addressed and mitigated, such as the price gap with grey hydrogen.

Hydrogen Europe reviewed announced projects in the EU aiming to replace fossil fuels with low-carbon and renewable hydrogen in areas such as refining, ammonia production, steel, methanol production, industrial heating and as a feedstock in other chemical processes. Their Clean Hydrogen Monitor expects that by 2030, the total planned consumption of clean hydrogen in the tracked industrial projects could amount to 6.1 Mt hydrogen per year.

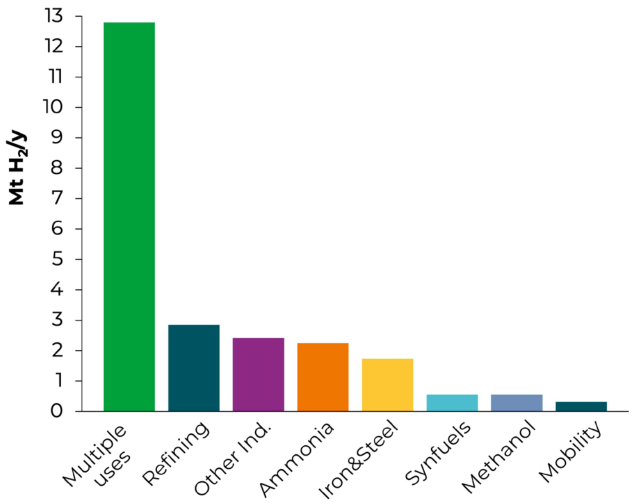
Even though most of the technology needed to enable innovative uses of hydrogen are still at demonstration or prototype stage, there are cases where the technology is already more advanced. For instance, the world's first ferry sailing on zero-emission liquid hydrogen (MF Hydra) started operations in early 2023 in Norway.[92] Besides, the HyInHeat project aims to use hydrogen as a fuel for high temperature heating process for the aluminium and steel industry.[93] Another example is in Sweden, where H_2 Green Steel is moving towards the construction of the first large-scale green steel plant in Europe. The project will use thyssenkrupp nucera water electrolysers with a capacity of more than 700 MW.[94]

For proven uses and for innovative applications, the rapid scale-up of renewable hydrogen production and a clear regulatory environment are fundamental to supply affordable renewable hydrogen and derivatives to both traditional and innovative end-uses.

Figure 16 shows the nominal hydrogen production capacity divided by the main end-use sectors in Europe for 2030. The largest category refers to projects that indicated that their output will serve to multiple end-use sectors.

91 IEA (2023). Global Hydrogen Review 2023. (Link)
92 Marine Insight (2023). World's First Hydrogen Ferry MF Hydra Sailing On Zero-Emission Liquid Hydrogen Put Into Operation. (Link)
93 HyInHeat. About the project. (Link)
94 Thyssenkrupp (2023). thyssenkrupp nucera Supplies the Electrolyzers for H2 Green Steel to Build One of the Largest Integrated Green Steel Plants in Europe. (Link)

Figure 16
Nominal hydrogen production capacity in the main end-use sectors in Europe (2030)[95]



Hydrogen derivatives will play an important role in scaling up the hydrogen economy

As pointed out above, hydrogen derivatives and feedstocks, such as ammonia, methanol and synthetic hydrocarbons have the advantage of being easier to store and transport over long distances (e.g. over 2,500 km), compared to pure hydrogen. However, as these by-products need additional energy and feedstocks to be produced, their costs are higher than pure hydrogen. From the total production of hydrogen derivatives, ammonia and synthetic methane represent the first and second largest share, respectively. The production of ammonia to be used as a fuel and feedstock reached 0.71 Mt of hydrogen in 2022.[96]

EU MS will need to import hydrogen derivatives to cover an increasing demand and be closer to the 10 Mt of renewable hydrogen imports referred to by the REPowerEU Plan. The European Commission launched the European Hydrogen Bank, an EU-wide auction mechanism for green hydrogen. After a first round for internal production that started at the end of November 2023, the European Commission plans to link the instrument to Germany's H2Global program, an auction mechanism for imports of hydrogen derivatives. This would extend the scope of the European Hydrogen Bank to projects located outside the EU.[97]

As stated in the previous section, the development of hydrogen infrastructure will play a key role to enable not only domestic renewable hydrogen production, but also increasing the amount of hydrogen and derivatives imported from outside the EU.[98]

95 IEA (2023). Hydrogen Production and Infrastructure Projects Database (Last updated October 2023). (Link)
96 IEA (2023). Global Hydrogen Review 2023. (Link)
97 Guidehouse Insights (2023). Electrolyzer Supply and Demand Outlook. (Link)
98 European Hydrogen Backbone (2023). Implementation roadmap – Cross border projects and costs updates. (Link)

3.2 Innovation & Technology

Topic 1: Offshore hydrogen production

North Sea, Gulf of Biscay

Lhyfe, PosHYdon, HYGRO, AquaVentus, HOPE

Late 2020s — TRL 6

Currently all pilots are <10 MW

With **further buildout of renewable energy capacity**, integration in the energy system will become **increasingly challenging**. For offshore wind integration, offshore hydrogen production and transport to shore could mitigate these challenges. Transmission cost for hydrogen is lower than for electricity and offshore pipelines enable the aggregation of offshore hydrogen production from several wind farms.

Several companies are **working on pilots to enable hydrogen production offshore**, overcoming challenges such as cost, spatial footprint, weight, and operation under harsh offshore conditions.

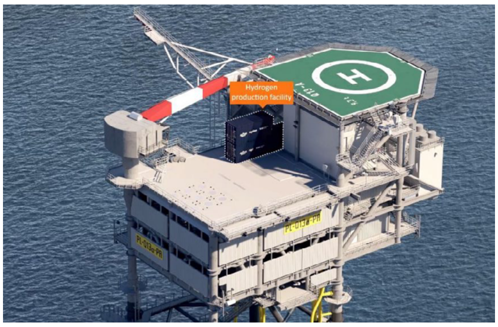
In the **Netherlands**, the Ministry of Economic Affairs and Climate has indicated they want to realise **two demonstration projects for offshore hydrogen production**, one <100 MW pilot (earliest 2027) and one of 500 MW (by 2031). More information will be available towards the end of the year (Link)

Project examples

PosHYdon

13 km away from the Dutch shore, green hydrogen will be produced on the fully electrified Q13a-A platform of Neptune Energy. Seawater will be demineralised and converted into hydrogen via electrolysis, supplied by wind power. The pilot aims to investigate and learn from the integration of energy systems at sea and producing hydrogen in an offshore environment to help develop large-scale, green hydrogen production systems for offshore use. — Link

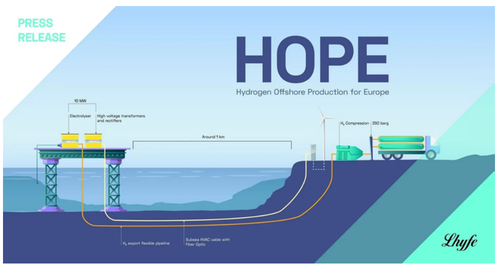
Partners: Nexstep, TNO, Neptune Energy, Gasunie, DEME, NOGAT, NGT, NEL Hydrogen, InVesta, TAQA, Hatenboer



Hydrogen Offshore Production for Europe (HOPE)

After inauguration of an offshore hydrogen unit in a 1 MW floating wind turbine in 2022, a consortium now prepares for a 10 MW offshore hydrogen asset, where the hydrogen will be landed to shore with a composite pipeline and brought to customers in industry and the transport sector. Operation is expected to start mid-2026. — Link

Partners: Lhyfe, Alfa Laval, Plug, Strohm, EDP NEW, ERM, CEA, POM and DWR eco



Topic 2: Flexibility & modularity for H2

Various locations worldwide

Various technology providers

Already available – TRL 8/9

Scale-up in manufacturing and implementation will depend on hydrogen value chain

With **further buildout of renewable energy capacity**, integration in the energy system will become **increasingly challenging**. Flexible operation and modular systems for hydrogen production will become increasingly relevant across the value chain, as this would enable the integration of intermittent renewables in the system. Also, hydrogen storage and compression capabilities will be required to optimise the operation of the future energy system.

Hydrogen production innovation (TRL 8/9)

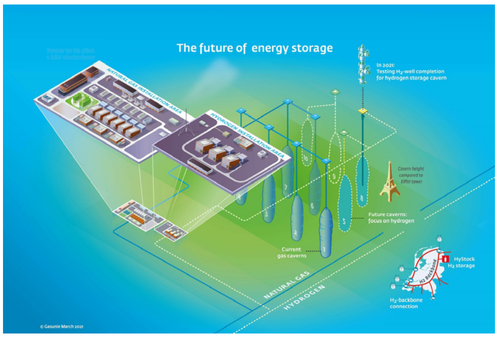
To mitigate the restricted nominal load capabilities of electrolyser equipment and to enable the scale up of hydrogen production assets, several technology providers are developing modular systems. By connecting these in parallel and containerising them, the systems are scalable and more agile in operation.

Example companies: Enapter, ITM Power, Topsoe, Green Hydrogen Systems, Cummins

Large-scale hydrogen storage (TRL 8/9)

The role of large-scale hydrogen storage is getting increasingly recognised for the future energy system. They will play a role for security of supply, for a stable supply despite green hydrogen production, and for power production. Several EU storage system operators are working on the topic by doing research projects and pilots. This year, they have also called for expressions of interest and open season to test market interest in storage volumes, which were welcomed by the market with great interest.

Example companies: HyStock, Storengy, Uniper



Hydrogen compression (TRL 9)

Hydrogen compression assets will need to be able to cope with the intermittent production of hydrogen from renewable energy sources and to safely transport and storage the gas. Compressor manufacturers are developing their assets to meet green hydrogen needs, for instance by ensuring that the compressor can compensate for fluctuations in hydrogen production volumes.

Example companies: Atlas Copco, Howden, Siemens Energy

4. CO_2 trends

Key takeaways

Existing synergies between CCUS development and low-carbon gases (biomethane and H_2) can be further leveraged as climate mitigation solution to achieve net-zero. Critical applications include capturing biogenic CO_2 from the biogas industry, synthetic fuels and synthetic methane production, low-carbon hydrogen, and bioenergy production with CCS.

CO_2 capture potential for permanent sequestration in onshore and offshore locations is currently largely untapped. The Net Zero Industry Act will catalyse the EU CCUS strategy with a proposed injection target of 50 Mt CO_2/y by 2030. To meet its climate objectives, the EU CO_2 capturing capacity needs to triple between 2030 and 2050, reaching 150 Mt/y.

CCUS project development across Europe is gaining momentum with more than 60 projects announced in the past five years. Three large-scale CCS projects have taken positive FID: Porthos in the Netherlands, Ørsted Kalundborg CO_2 Hub in Denmark and Longhip in Norway. TSO-driven initiatives in the EU are catalysing projects across the CCUS value chain, as highlighted in the recent CCUS infrastructure publication of Gas for Climate.

4.1 Markets

4.1.1 Supply & Demand

Carbon capture, utilisation and storage (CCUS) is a relevant climate mitigation solution

CCUS technologies are progressively becoming a prominent part of climate mitigation solutions. Alongside with renewables energy supply, efficiency measures and reductions in energy intensity, CCUS will play a critical role in achieving net-zero emissions by 2050, as highlighted in reports from the Intergovernmental Panel on Climate Change (IPCC), the International Energy Agency (IEA), and the European Commission (EC).

The most recent IPCC report indicates that CCUS deployment is required before 2030 to meet the Paris Climate Goals in 2050. CCUS is seen as a mitigation option to achieve net emission reduction goals, targeting energy supply and industries.[99] Additionally, the energy models used in the IPCC analysis outline that CCUS is not limited to short-term mitigation plans and will need to remain in place well beyond 2050.

CCUS technology involves the capture, utilisation, transport, and storage of carbon dioxide. Generally, CO_2 is captured by large point sources or industrial and power generation clusters that uses fossil fuels or biomass as fuel or feedstock in their operation processes. When CO_2 is not used on-site, it is compressed, transported, and injected to be stored in geological formations such as saline aquifers or depleted gas reservoirs.

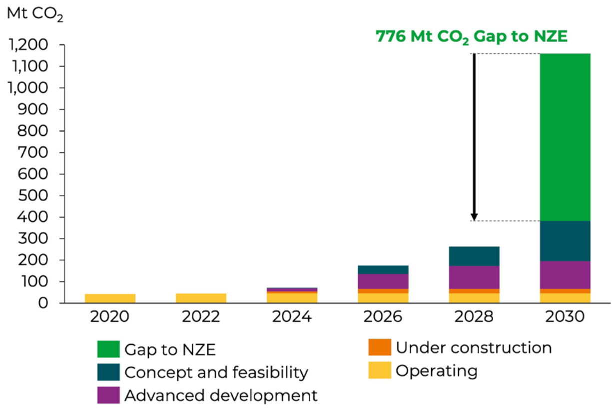
99 IPCC (2023). AR6 Synthesis Report: Climate Change (Link)

CCUS used in the transition to net-zero emissions includes technologies such as (1) CO_2 capture and utilisation (CCU), (2) CO_2 capture and storage (CCS), (3) Direct Air Capture and Storage (DACS), and (4) Bioenergy with Carbon Capture and Storage (BECCS). When CO_2 is captured directly from the atmosphere (DACCS), or from biomass (BECCS), CCS provides the carbon capturing and storage component of these carbon dioxide removal (CDR) methods.

According to the IEA, the extent to which CCUS mitigation will be able to contribute to achieving net zero emissions depends largely on the technological readiness level, which varies considerably by application and technology employed. Among the CCUS mature and early adoption technologies that are forecasted to be scaled up in the short term are direct reduction iron (DRI), ammonia and methanol via chemical absorption, and hydrogen production from natural gas. [100] Urea and concrete are the most CCU mature technologies. In terms of readiness level, IPCC reports CO_2 capture and subsurface injection being a mature technology for gas processing and enhanced oil recovery. CCS is less mature in the power sector, as well as in the cement and chemicals production, where its deployment represents a critical mitigation option.

Globally, CCUS deployment has fallen short of the forecasted expectations. There has been a significant surge in momentum in the recent years, with over 500 CCUS projects at different stages of development. Despite this progress, CCUS deployment is currently not on track and remains insufficient to meet the Net Zero Energy (NZE) scenario, with a 776 Mt of CO_2 gap to be filled by 2030. CCUS projects are facing higher capital costs than forecasted and underperforming on the capture rate.

Figure 17
Capacity of current and planned large-scale CO_2 capture projects vs. the Net Zero Scenario, 2020-2030 (IEA)



Currently, CCUS projects face significant barriers to scale-up, such as high cost of implementation, low technological readiness for some applications, and the need for extensive infrastructure deployment (CO_2 storage and pipeline or shipping infrastructure). In the Communication on Sustainable Carbon Cycles, the European Commission proposed that by 2030 at least 20% of carbon used in products should come from sustainable carbon sources, though under the current conditions this is unlikely to be met.[102] The proposed ambition to achieve 50 Mt/y CO_2 injection target by 2030 launched as part of the Net Zero Industry Act by the European Commission might catalyse CCUS projects. [101]

Deploying CCUS enables the scale-up of adjacent technologies, such as low-carbon hydrogen production

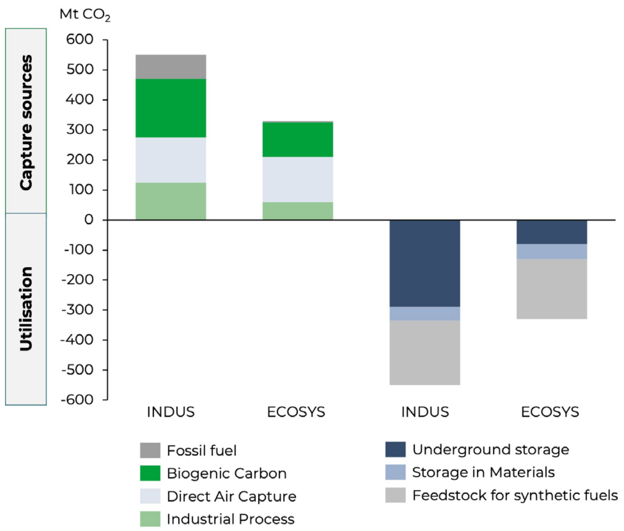
According to modelling by the European Commission and the IPCC, to meet its climate objectives, the EU will need to capture and store at least 150 Mt CO_2/y of atmospheric or biogenic origin by 2050.[102]

The European Commission's modelling assessment showcased in Figure 18 presents two possible scenarios: (1) INDUS with ~ 550 Mt of CO_2 captured and used in 2050, and (2) ECOSYS with ~ 330 Mt of CO_2 captured and

100 IEA (2020). CCUS Technology Innovation – CCUS in Clean Energy Transitions analysis (Link)
101 IEA (2023). Net Zero Industry Act CCUS: Policies (Link)
102 CCUS Vision Working Group (2023). A Vision for Carbon Capture, Utilisation and Storage in the EU (Link)

used in 2050. In the "ECOSYS" scenario, the focus is on enhancing carbon removal through ecosystem restoration, and increased changes in lifestyle and consumer choices, including less carbon-intensive diets that allow land to regenerate natural ecosystems. In contrast, the "INDUS" scenario relies more on large-scale industrial solutions for capturing, recycling, and storing CO_2. Both scenarios align with the EU's goal of climate neutrality by 2050 and are in line with the European Green Deal.

Figure 18
Estimated Annual CO_2 Capture and Utilisation volumes (Mt/y) for the EU in 2050 Under Two Possible Scenarios[103]



To achieve CO_2 captured rate presented in the ECOSYS and INDUS scenarios, the EU will need to deploy CCUS at scale, through a diverse range of solutions for removing CO_2 and creating sustainable non-fossil carbon sources. The main CCUS applications are presented below. Currently, over 60 CCUS projects have been announced in Europe since 2019[104], but only three large-scale CCS projects (Norway's 'Longship project', Ørsted 'Kalundborg CO_2 Hub' in Denmark and 'Porthos' in the Netherlands discussed below in the case study) have taken a positive FID and are now under construction. The progress in CO_2 capture development stems from the near-term potential of available permanent storages such as Norway's Northern Lights, which are currently reliant on investment from national governments.[105]

Applications of CCS and source of CO_2 supply

- **Permanent carbon removal**: Geological storage of CO_2, obtained from direct air capture (DACS), bioenergy processes (BECCS), and enhanced weathering removes large volumes of carbon from the atmosphere, essential for balancing greenhouse gas emissions at net zero and reducing atmospheric CO_2 concentrations. The Integrated Assessment Model futured by IPCC presents a median of around 300 Mt/y of BECCS in Europe by 2050. Besides, DACS will play a smaller role with around 195 Mt/y in 2050.[106] Permanent removal include fossil CO_2 emissions abatement through storage in geological formations or permanent CO_2 mineralisation.

- **Emissions mitigation in hard-to-abate industries**: CCS helps reduce unavoidable emissions from industries like cement, steel, chemicals, and waste incineration, where emissions occur due to industrial processes and operations.

- **BECCS in thermal power plants**: While wind, solar and hydro generation will decarbonise the majority of power supply, CCS with bioenergy (BECCS) in thermal power plants used for peak load enables faster and more complete decarbonisation with negative carbon cycle potential. Ørsted Kalundborg Hub is a prime application of achieving negative carbon emission by capturing biogenic CO_2 from two Danish combined heat and power plants. The project will start operation in 2025.

- **Biogenic CO_2 from biogas and biomethane industry**: biogenic CO_2 is generated both in the production pathways of biogas and in the

103 Commission staff working document (2021). Sustainable carbon cycles for a 2050 climate-neutral EU Technical Assessment (Link)
104 Zero Emission Platform. (Link)
105 CCUS Vision Working Group (2023). A Vision for Carbon Capture, Utilisation and Storage in the EU (Link)
106 DNV (2021). A pathway to net zero emissions (Link)

process of upgrading biogas to biomethane. Capturing CO_2 from these industries would be low cost due to high purity, and biogenic origin of CO_2 implies negative carbon cycle contribution to decarbonisation.[107]

- **Hydrogen production**: CCS can decarbonise hydrogen production from fossil fuels with steam methane reforming (SMR) or autothermal reforming (ATR), supporting low-carbon fuel targets, provided capture rates are maximised and supply chain methane leakages are minimised.

- **Biogenic CO_2 from biogas industry**: the biogas biomethane value chain can produce biogenic CO_2 via anaerobic digestion, thermal gasification or supercritical water gasification. During biogas upgrading into biomethane, biogas is split into CH_4 and CO_2. The CO_2 is captured at relatively low cost due to its high purity.

Applications of CCU and use of CO_2

- **Sustainable product feedstock**: Biogenic or atmospheric CO_2 captured via BECC, DAC and from biomethane industry can replace fossil CO_2 as an alternative feedstock to produce fertilizers, plastics, and fuels such as methanol, synthetic diesel, synthetic kerosene and chemicals such as urea, ethylene, benzene. Using atmospheric or biogenic CO_2 can contribute to product availability in a net-zero Europe. High emission reduction potential compared to the fossil equivalent use.

- **CO_2 for synthetic methane production**: an alternative route to biomethane produced via anaerobic digestion or thermal and hydrothermal gasification could be synthetic methane produced via methanation combining H_2 and captured CO_2.

- **Building materials**: CO_2 can be used in the production of building materials through mineralisation in concrete or aggregates, providing a climate change mitigation function similar to geological storage, when the CO_2 remains isolated. This conversion pathway is typically less energy intensive than for sustainable product feedstock and involves permanent storage of CO_2 in the materials.[108]

CCU deployment relies on the development of temporary storages and connection to the CO_2 network. Currently, EU CO_2 infrastructure (CO_2 pipeline and storage) is limited. Regarding non-permanent storage options, onshore fields might be not suitable for safety and pressure level reasons, while offshore fields and salt cravens represents a more feasible alternative. Offshore storages for CCU requires a CO_2 system that facilitate both injection and offtake of CO_2 from the facility. Other factors that affect CCU applications are CO_2 quality and whether CO_2 is needed in liquid or gaseous form.

Deploying CCUS also provides the added benefit of enabling the scale-up of adjacent technologies. This includes the ramp-up of the hydrogen economy by contributing towards low-carbon hydrogen production and enabling the circular economy of carbon through recycling of industrial process and biogenic CO_2 into carbon neutral materials or the production of synthetic fuels.

4.1.2 Infrastructure and storage

CO_2 infrastructure in EU is yet to be developed to contribute to EU-wide decarbonisation

CO_2 infrastructure (transport and storage) play a critical role in the deployment of CCUS technologies. Options to transport CO_2 include pipeline, rail, shipping and truck. The viability of each option is dependent on several factors including, the volume of CO_2 to be transported, cost, and distance. Table 1 presents a high-level assessment of CO_2 transport options.

107 European Biogas Association (2022). Biogenic CO_2 from the biogas Industry (Link)
108 IEA (2020). CCUS Technology Innovation – CCUS in Clean Energy Transitions analysis (Link)

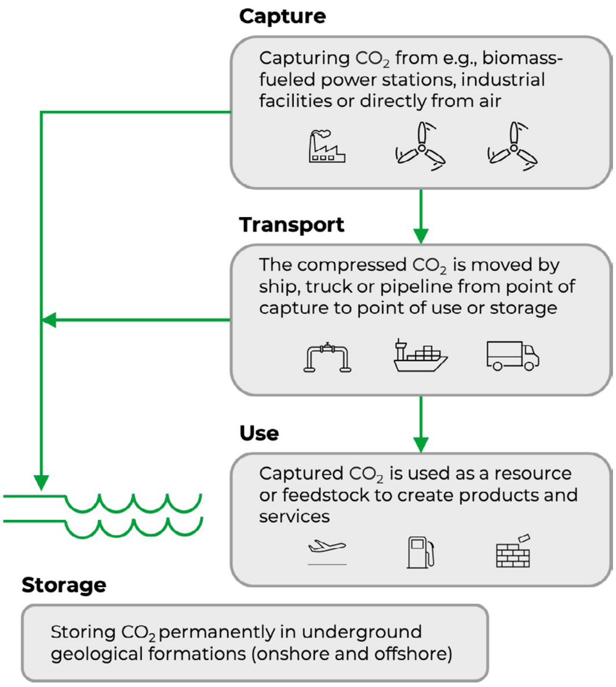
Table 1
CO_2 transport options[109]

Transport option	Upsides	Downsides	Use cases
Pipeline	→ Since CO_2 can be transported in various phases, (either >80 bars in liquid form or at 40 bar in gaseous form), it can result in lower conditioning costs, less strict composition conditions and less energy required. → Safest option for transport.	→ Requires the development of a regulatory framework and/or support schemes to allow sizing the pipeline infrastructure to future CO_2 injection demand. → Requires necessary pipeline infrastructure.	→ Cost-effective option for large CO_2 volumes transported. → Linepack potential.
Shipping	→ Suitable for both seasonal and baseload emitters and remotely placed emitters. Easy to scale capacity up. → Flexibility in the CO_2 destination (different storage sites can be reached from a single export terminal).	→ Requires necessary port infrastructure. → Shipping is more OPEX intensive, pipelines are more CAPEX intensive. → Operational risk due to dependency on weather conditions at the port. Temporary tank needed.	→ Shipping can be used with offshore sequestration and geological storage sites. → Import and export terminals will also be needed to connect ships to emitters and storage systems. → Terminals will also be the destination of onshore collecting logistics, which can also be in various forms depending on the volumes, distance etc.
Rail	→ Can be a cost-effective option for transporting small and medium quantities of CO_2 across medium to long distances.	→ Likely that trucks or pipelines will be needed for CO_2 to be carried to the rail options. → Current rail infrastructure is already at maximum capacity in many EU regions, limiting rail as a viable option.	→ A logistic solution to connect small or remote emitters to a main infrastructure (e.g., pipelines, terminals) or as a kick-off solution.
Truck	→ Viable option in a project ramp-up phase.	→ Can be costly and relatively inefficient option especially in highly congested areas. → Overall emissions reduction is compromised if fossil transport fuels are used in trucks.	→ Transporting CO_2 by truck is a viable option for small quantities. → A logistic solution to connect small or remote emitters to a main infrastructure (e.g., pipelines, terminals) or as a kick-off solution.

109 Gas for Climate (2023). Best practices of CCUS infrastructure in Europe (Link)

As presented in Figure 21 geological storage is an essential component of CCUS infrastructure, depending on the type of CO_2 use and capture and the mode of transport. Europe has an estimated geological storage capacity of around 500-560 Gt, including saline aquifers, storage reservoirs and hydrocarbon fields both onshore and offshore.[110,114] For sequestration and permanent geological storage in onshore and offshore fields there is sufficient capacity potential: saline aquifers across Europe have an estimated storage capacity of , storage reservoirs capacity ranges between 31 and 54 Gt and hydrocarbon fields capacity is around 25 Gt, shown in Figure 22.[111] The infrastructure needed to exploit offshore locations potential is the connection from point emitters to a central point from which an offshore pipeline or large-scale vessel transport CO_2 to the geological storage. CO_2 quality is not critical for permanent removal, differently from the CCU temporary storage use.

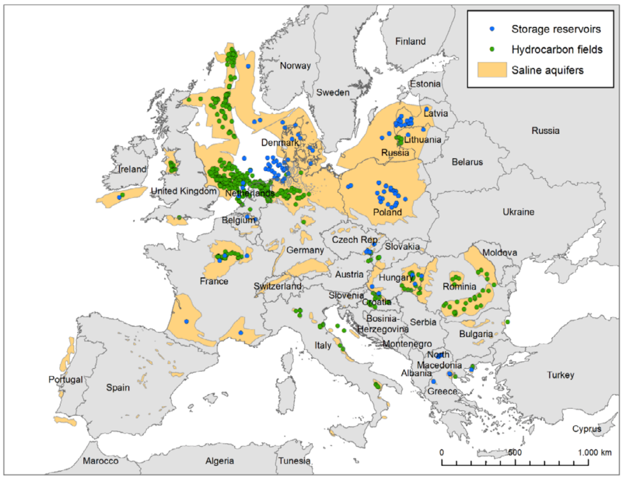
Figure 19
CCUS value chain[112]



There is an expanding gap between the growing need for and the availability of CO_2 infrastructure due to the slow pace at which CO_2 transport, and storage projects are being developed. CO_2 storage projects typically entail a long development cycle because of large lead times to permit and develop sites, assessment of detailed geological data, and high upfront investments.

However, timely and coordinated action between the private sector and governments can accelerate the deployment of these projects towards reaching the proposed target of 50 Mt/y of CO_2 storage capacity by 2030 proposed by the European Commission in the Net Zero Industry Act.[113]

Figure 20
Potential locations for CO_2 storage capacity across Europe[114]



110 ENTEC (2023). EU regulation for the development of the market for CO_2 transport and storage (Link)
111 Danish Ministry of Climate, Energy and Utilities (2021). EU Geological CO_2 storage summary (Link)
112 European Commission (2023). Climate action, Carbon capture, use and storage (Link)
113 IEA (2023). Net Zero Industry Act: CCUS Policies (Link)
114 Danish Ministry of Climate, Energy and Utilities (2021). EU Geological CO_2 storage summary (Link)

TSOs are well-positioned to develop a CO_2 pipeline network across Europe

There is an opportunity for TSOs to play an important role, as they are well positioned to develop open access and non-discriminatory pipeline infrastructure. A CO_2 transport network owned and operated by TSOs prevents inefficiencies with a holistic view of the overall CCUS market, avoiding lock-ins due to decision-making based on individual business interests. As a result of this broader view, a level playing field is created between different industrial clusters. Moreover, a potential alternative to transport CO_2 is by repurposing natural gas network. The transport infrastructure can be built and dimensioned in such a way that non-discriminatory access can be granted to all parties with a carbon capture intention.

However, the speed of deployment and viability of TSOs to develop the infrastructure will depend on the policy framework. In addition, the geographical spread of storage potential across Europe necessitates TSO collaboration and best practices will need to be leveraged to develop cross-border infrastructure. In the recent Gas for Climate publication on CCUS infrastructure in Europe, selected TSO-driven CCUS projects across EU were showcased, signifying momentum in development and underlying the need for stronger collaboration between public and private entities across borders to ensure the buildout of large-scale and capital-intensive CO_2 infrastructure.[115] The recently published list of 13 PCIs and 2 PMIs further concretise this momentum and underlines the importance of cross-border CO_2 infrastructure for the common EU decarbonisation interest. [116]

115 Gas for Climate (2023). Best practices of CCUS infrastructure in Europe
116 European Commission (2023). Annex PCI PMI list (Link)

4.2 Innovation & Technology

Topic 1: CO_2 in the Netherlands

Netherlands, Dutch North Sea

Porthos, OCAP, Carbyon

Porthos: 2026
Carbyon: 2030-2040s

Porthos: 2.5 Mt/y
OCAP: 0.6 Mt/y

As described in section 4.1.1, there is a clear need for **carbon capture, utilisation and storage**. The required infrastructure and solutions will develop around industry and storage locations. In the Netherlands, there are various projects and companies working on CO_2 solutions, ranging from CCS, CCU and Direct Air Capture, which are highlighted in this case study.

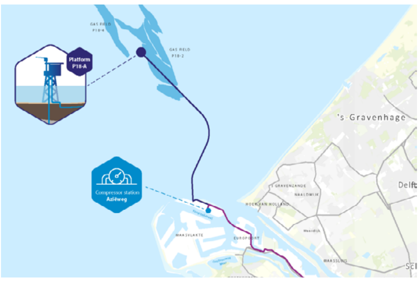
In our previous Gas for Climate report "Best practices of CCUS infrastructure in Europe", an extended list of CCUS projects was highlighted from across Europe.

Project examples

Carbon Capture and Storage — Porthos

After reaching FID, the first major CO_2 transport and storage system in the Netherlands will start construction 2024. The €1.3 billion project should be operational in 2026, storing 2.5 million tonnes of CO_2/y for 15 years. The CO_2 of Air Liquide, Air Products, ExxonMobil, and Shell, equal to around 10% of Rotterdam's industry emissions will be captured and to depleted gas fields around 20 km off the coast in the North Sea.

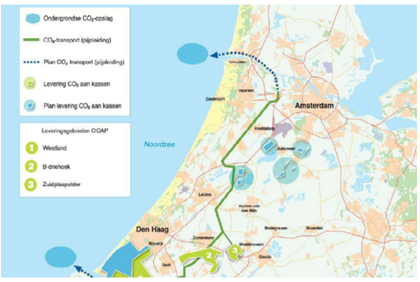
Project partners: Energy Beheer Nederland, Gasunie, Port of Rotterdam



Carbon Capture and Utilisation — OCAP pipeline (TRL 9)

The Dutch horticulture sector needs CO_2 for increased and better crop yield. Since 2005, CO_2 is captured at industrial sources of Shell and Alco and distributed to greenhouses via a network of 250 km. This sector wants to be more sustainable and connect more CO_2 sources in the future. If in the future the CO_2 demand is lower than supply, the pipeline can also be connected to CCS facilities in the proximity of the network.

Project partners: Linde, Horticulture Netherlands, WUR, Tomatoworld, B-Mex, Letsgrow, Shell and Alco



Direct Air Capture — Carbyon (TRL 5)

Dutch startup that is looking to build modular Direct Air Capture (DAC) assets. They are designing to capture 200-500 tons per year per machine by using a fast-swing process with modified fibre membrane materials that should allow a cycle of carbon capture every 6 minutes. This is key to lower the energy consumption as well as the cost. They are currently at prototype scale but are working towards capturing CO_2 at below 100 euro/tonne, of which 25 euro/tonne would consist of CAPEX.

Similar companies: Climeworks, Carbfix

5. Policy developments for renewable and low-carbon gases

Key takeaways

The new policy architecture of the Fit-for-55 Package will have a large impact on the entire value chain of hydrogen, biomethane and CO_2. The introduction of mandatory quotas creates more demand and provides investors with certainty. The NZIA aims to support the European manufacturing capacity of net zero technologies such as enabling CCS projects. National and cross-border Infrastructure projects can benefit from faster permit granting.

REFuel EU Aviation and FuelEU Maritime set important obligations that can unlock further RFNBOs uptake. On the aviation sector, a mandatory blending obligation on jet suppliers for Sustainable Aviation Fuels of 42% by 2030 was introduced. On the other side, shipping companies shall reduce the GHG intensity of energy used on board 6% by 2030.

To facilitate the certification of RFNBOs, the EU Commission defined the sustainability criteria to follow. Producers shall comply with criteria regarding greenhouse gas savings requirements, renewable electricity sourcing, and sourcing of carbon (e-fuels), among others.

5.1 Key policies shaping the market for renewable and low-carbon gases

5.1.1 Green Deal and the Fit-for-55 Package

As part of the Green Deal that aims to reach climate neutrality by 2050, the 27 EU MS also pledged to reduce emissions by at least 55% by 2030, compared to 1990 levels. To reach the 2030 goal, the EU drafted an important set of proposals to revise and update EU legislation (Fit-for-55 package). In relation to renewable and low-carbon gases, the Fit for 55 package includes:[117]

→ Renewable Energy Directive III (RED III)[118,119]

117 European Council. Fit for 55. (Link)
118 European Commission. Renewable Energy Directive. (Link)
119 The legislation was adopted with 470 votes to 120, with 40 abstentions. It will now have to be formally endorsed by Council to come into law. (Link)

- REFuel EU Aviation Regulation[120] and FuelEU Maritime regulation[121]
- Hydrogen and Decarbonised Gas Market Package[122]
- Revised Regulation on Deployment of Alternative Fuels Infrastructure (AFIR)[123]
- Hydrogen and Decarbonised Gas Market Package (Gas Package)[124]

The table below presents the main sectoral targets for RFNBOs introduced by the above policy and regulatory instruments.

Table 2
EU policy and regulation impacts on RFNBOs demand

Policy/ Regulation	Impact on RFNBO demand
RED III	→ The revision sets out binding, step-by-step and sector-by-sector targets for the share of renewable energy sources (RES) in gross final energy consumption. The binding 2030 target was increased to a minimum of 42.5%, up from 32%. There is an additional 2.5% indicative top up that would allow the EU to reach 45%. → The RFNBO share for hydrogen used in industry shall reach 42% by 2030 and 60% by 2035. → 5.5 % of energy used in transport shall be supplied by advanced biofuels and RFNBOs by 2030 (and 1% in 2025). RFNBOs must account for at least one percentage point by 2030.
REFuel EU Aviation	→ Mandatory blending obligation on jet fuel suppliers for Sustainable Aviation Fuels (SAF): 2% by 2025, 6% by 2030, 20% by 2035, 34% by 2040 and 70% by 2050. → A dedicated sub-target for synthetic fuels derived from green hydrogen: 1.2% by 2030, 5% by 2035 and 35% by 2050.
FuelEU Maritime	→ Mandatory obligation on shipping companies: GHG intensity of energy used on board ships to be reduced by 2% by 2025, 6% by 2030, 14.5% by 2035, 31% by 2040, 62% by 2045, 80% by 2050 (compared to reference value of 91.16 g CO_2eq per MJ). → There is a 'multiplier' to be used when calculating the GHG intensity of the energy used allowing the energy from RFNBOs to count twice. → 2% RFNBO usage target as of 2034 if the Commission reports that in 2031 RFNBO amounts to less than 1% in the fuel mix.

The EU Commission clarified the sustainability criteria for RFNBOs

The EU Commission defined sustainability criteria for RFNBOs through the adoption of two Delegated Acts on Articles 27 and 28 of RED II.[125] Thus far, these criteria are only applicable to the transport sector. However, they are expected to be extended to other sectors, and in particular industry.

Revised Regulation on Deployment of Alternative Fuels Infrastructure (AFIR) will shape the refuelling infrastructure

The AFIR regulation sets mandatory deployment targets for electric recharging and hydrogen refuelling infrastructure for the road sector as well as for electricity supply to stationary aircraft.[126] From 2030 onwards, hydrogen refuelling infrastructure must be deployed in all

120 European Council (2023). Council and Parliament agree to decarbonise the aviation sector. (Link)
121 European Council (2023). FuelEU Maritime initiative: Provisional agreement to decarbonise the maritime sector. (Link)
122 European Council (2023). Gas package: member states set their position on future gas and hydrogen market. (Link)
123 European Parliament (2023). Revised Regulation on Deployment of Alternative Fuels Infrastructure (AFIR). (Link)
124 European Commission. Hydrogen and decarbonised gas market package (Link)
125 The Commission adopted the draft text of these Delegated Acts on 13 February 2023, and they were published on 20 June 2023. Both Delegated Acts entered into force – unchanged from the draft text – on 10th July 2023.
126 European Commission (2023). European Green Deal: New Law Agreed to Deploy Sufficient Alternative Fuels Infrastructure. European Commission. (Link)

urban nodes and every 200km maximum along the Trans-European Transport Network (TEN-T) to construct a network sufficiently dense for usage of hydrogen vehicles across Europe.

The REPowerEU plan increased the ambition of targets set in the Fit-for-55 package

In 2022, the EU Commission introduced the REPowerEU plan with 3 main goals: clean, affordable and secure energy supply to EU MS. The REPowerEU plan has increased the ambition of several targets set in the Fit-for-55 package:

- **Renewable energy**: the objective of RES share in gross final consumption increased to 45% instead of 40% by 2030.
- **Biomethane**: EU recommends every MS to develop its own biomethane strategy and plans to produce 35 bcm/y by 2030.
- **Hydrogen**: The projected demand in renewable and low-carbon hydrogen in 2030 has been raised from 5 Mt to 20 Mt of hydrogen (10 Mt domestic production and 10 Mt imports).

The Net Zero Industry Act (NZIA) can incentivise the scale-up of domestic manufacturing capacities for key technologies, such as electrolysers

Besides incentivising demand and supply of hydrogen with targets and support schemes, the EU also intends to create a simplified and favourable regulatory environment to support the European industry, which will be key to produce more electrolysers, among other low-carbon technologies.

In particular, the Net Zero Industry Act (NZIA) (proposal)[127] is part of the European Green Deal Industrial Plan and aims to decrease dependence on third countries for strategically important components and technologies. The proposed regulation defines a list of "net zero technologies", including the production of RFNBO and SAF, benefitting from shortened approval deadlines. It also defines "strategic net zero technologies", including electrolysers and fuel cells, biogas/biomethane and grid technologies, additionally benefitting from prioritized permitting and EU production targets.

The Hydrogen and Decarbonised Gas Market Package will set common rules to boost the penetration of renewable and low-carbon gases into the energy sector

Another important regulatory piece is the review of the EU gas market rules through the **Hydrogen and Decarbonised Gas Market Package (Gas Package).** The purpose of this package is to boost the European production, infrastructure, transport, trade and supply of renewable and low-carbon gases.

The Gas Package includes the revision of the Internal Gas Market Directive (Directive 2009/73/EC, "Gas Directive") and the revision of the Gas Market Access Regulation (Regulation EC 715/2009, "Gas Regulation"). With the mentioned revisions, the EU intends to enable a competitive decarbonised gas market as well as develop a cross-border and cost-effective hydrogen infrastructure. In November 2023, the Council and the Parliament reached a provisional political agreement on the directive. The regulation will be agreed at a later stage.[128]

The Gas Directive regulates the transmission, distribution, supply and storage of RE and low-carbon gases using the natural gas system and hydrogen system. As communicated in a recent EU press release, the Council and the Parliament agreed that:

- The TSOs and DSOs for hydrogen will be split.
- MS shall ensure the right of customers to switch supplier in a cost-efficient way.
- MS have also the power to decide on protective measures for vulnerable customers, for example, regarding disconnections.

127 European Commission (2023). Communication: A Green Deal Industrial Plan for the Net-Zero Age (Link)
128 European Council (2023). Internal markets in renewable and natural gases and in hydrogen: Council and Parliament reach deal. (Link)

- Network development plans for hydrogen, electricity and natural gas should be well coordinated and follow the energy efficiency first principle and prioritise the use of hydrogen in hard-to-decarbonise sectors.[129]

The Gas Package, among other areas, sets rules for third party access (TPA). The proposals intend to make sure that in principle, hydrogen network operators and hydrogen storage facility operators would be required to offer their services on a non-discriminatory basis to all network users, i.e. regulated grid access (entry-exit-system). Until 31 December 2030, negotiated grid access based on objective, transparent and non-discriminatory criteria should remain possible.

5.1.2 TEN-E regulation

The Trans-European Networks for Energy (TEN-E) Regulation's goal is to increase the interconnectedness of MS energy infrastructure by funding and facilitating strategic cross-border infrastructure projects. In 2022, the Green Deal led a revision of the regulation, resulting in the exclusion of natural gas infrastructure projects. In turn, projects concerned with hydrogen infrastructure and production (e.g. electrolysers) are now eligible.

The TEN-E regulation also outlines geographical priority corridors where connecting infrastructure is strategically highly valuable. If a project is located in one of these corridors and considered as important for the deepening of the EU energy markets, it may become a PCI (Project of Common Interest) and benefit from accelerated planning and permit granting and can be financed by the Connecting Europe Facility (CEF). If the infrastructure project concerns third countries, the TEN-E also contemplates the case of Projects of Mutual Interest (PMI), which benefit from similar benefits as PCIs. The latest list of PCIs and PMIs was published in November 2023.[130]

5.1.3 CO_2 policy developments

In September 2023, the Gas for Climate consortium has published a paper on the "Best practices of CCUS Infrastructure in Europe".[131] In this paper, an elaborate description has been given on the need for CCUS, the role of CO_2 infrastructure as enabler of CCUS and an analysis of CCUS projects and policies in the EU and in MS.

The report also included two main categories of policy recommendations for CCUS, namely the need for a comprehensive policy framework to ensure cross-border cooperation on planning of CO_2 infrastructure, and financial support schemes. More details on the state of CO_2 policy developments and CCUS projects of Gas for Climate members can be found in the respective paper.

Apart from the NZIA, which emphasizes the role of CCUS for the decarbonisation of industry, the EC will publish their Carbon Management Strategy, that will further detail the strategy for CO_2 transport, utilisation and storage. In August 2023, the European Commission concluded an open public consultation for this Strategy, which will contribute and help shape this strategy further. Publication of the Carbon Management Strategy is expected in Q1 of 2024.

129 European Council (2023). Internal markets in renewable and natural gases and in hydrogen: Council and Parliament reach deal. (Link)
130 European Commission. Press corner. (Link)
131 Gas for Climate (2023). Best practices of CCUS infrastructure in Europe. (Link)

GAS FOR CLIMATE
A path to 2050

Guidehouse

Disclaimer