2021

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

A Gas for Climate report

December 2021

GAS FOR CLIMATE
A path to 2050

Guidehouse

Imprint

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Date:
December 2021

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Design:
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Executive summary

The European Union (EU) aims to fully decarbonise its economy, which requires a complete overhaul of the energy system and its infrastructure by 2050. The Green Deal, as announced by the European Commission (EC) in December 2019, aims to achieve at least a 55% reduction in greenhouse gas (GHG) emissions by 2030 compared to 1990 levels. In July 2021, the EC adopted a package of proposals to make the EU's climate, energy, land use, transport, and taxation policies fit to meet its 2030 GHG reduction goals and put Europe on track to becoming the world's first climate-neutral continent by 2050 - making the European Green Deal a reality.

Over the past few years, a **series of studies by the Gas for Climate consortium** showed that renewable and low-carbon gases have an important role to play in the future EU energy system. Combined with the existing gas infrastructure, renewable and low-carbon gases can help achieve the transition to a net-zero energy system at the lowest societal costs. Two renewable and low-carbon gases are indispensable in decarbonising the European energy system: biomethane and green and blue hydrogen.

This market state and trends report is a concise addition to the comprehensive 2020 report, which provided an overview of key developments related to biomethane and green and blue hydrogen. This report identifies the most recent key trends across the value chain of biomethane and green and blue hydrogen in Europe. It focuses on indicators and project examples by collecting and combining factual and statistical information and showcasing the latest projects.

The **biomethane sector** in Europe is growing. In 2020, 32 TWh of biomethane was produced. In 2021, the number of biomethane plants grew by 13% to 992 plants (as of August 2021). France continues to rapidly increase its biomethane production with 306 upgrading plants in operation; it is now ahead of Germany, which has 242 upgrading plants in operation.

- **Anaerobic digestion (AD)** is still the most commonly used biogas production technique. To increase the yield of biogas and biomethane, **new pretreatments** are being developed to unlock additional feedstocks—for example, ligno-cellulose and wooden materials, which are only biodegradable in AD with additional treatments.
- Next to AD, **hydrothermal gasification** is scaling up and expected to be at full industrial scale by 2023-2025.
- To transport the produced biomethane, some countries are about to **upgrade their gas grid** because the decentralised biomethane production does not match with the current top-down structure of most national natural gas grids. **Reverse flow facilities** are being put in place to allow the bidirectional flow from the transmission to the distribution grid and vice versa. Today, 15 reverse flow facilities are in service in Denmark, France, Germany, and the Netherlands; 25 are under construction (Denmark, France, Belgium); and 16 feasibility studies have been announced (France, Italy).
- As fossil fuel and CO_2 prices continue to rise, biomethane is becoming more **popular in industry**. It is used, for example, in the chemical, steel, and food and beverages sector as feedstock to provide industrial heat or for cogeneration plants. In the **transport sector**, bio-liquified natural gas (LNG) and bio-compressed natural gas (CNG) are increasingly used for passenger cars and heavy duty trucks. Bio-LNG is sought after by the maritime shipping sector as well. Captured CO_2 from biogas is becoming a valuable climate-neutral feedstock used to replace fossil-based CO_2 in industry.

The **development of biomethane** differs in the Gas for Climate member states due **to different strategies and support schemes**. Most countries announced targets (binding and non-binding), and only Spain and Greece do not have support schemes. The following support mechanisms are used:

- Quota system (Belgium and Italy)
- Feed-in premium (Denmark and the Netherlands)
- Feed-in tariffs (France and Germany)
- Fiscal incentives (Sweden)

The **green hydrogen sector** is also developing rapidly. Around 50 GW of renewable hydrogen production capacity has been announced to be deployed in the EU by 2030, 25% more than the EU's 40 GW target.

- To keep up with the growing number of projects, **electrolyser gigafactories** totalling over 20 GW/year of capacity by 2025 have been announced, with 88%—almost 18 GW/year—of capacity in Europe.

Technological developments around the **four main electrolyser technologies** indicate a trend towards pressurised hydrogen production and increased levels of integration with renewable energy sources. These developments, next to increased deployment, could lead to a green hydrogen **levelised cost reduction** of around 36% by 2025 to below 2.5€/kg.

The **blue hydrogen market** is positively affected by rising carbon prices, hitting €60/tCO_2 in the EU emissions trading system (ETS). This increase improves the business case for blue hydrogen over grey hydrogen, but the recent rise in natural gas prices renders both blue and grey hydrogen uncompetitive (> €4/kg H_2) with alternatives such as green hydrogen. Gas prices are expected to return to normal levels, while the carbon price in the EU ETS is expected to further increase.

Hydrogen transport and storage are key pillars of a future hydrogen economy, and transport and storage projects are moving forward with several Important Projects of Common European Interest (IPCEIs). Underground hydrogen storage trials are ongoing in all geologies and are expected to reach competitive cost levels on a seasonal timeframe. Developments in large-scale hydrogen compression in the coming years will further enable the rollout of large-scale hydrogen transport and storage.

Developments on the industrial demand for green hydrogen side have been kickstarted by the EC in the Fit-for-55 package, by proposing a mandate of **50% green hydrogen share in industry by 2030**. In the **steel sector**, many steelmakers have announced a switch to hydrogen-based steelmaking. Announced plans alone add up to 30% of current primary steel capacity in the EU by 2030, which would lead to around 80 TWh/year of hydrogen demand by 2030, signalling a key trend.

Another potentially large hydrogen demand market is **e-fuels**. This market will likely see a surge in adoption in Europe due to an EU mandate, possibly leading to around 90 TWh/year of hydrogen demand for e-fuels by 2030. The proposal of a global carbon price has accelerated the discussion on future decarbonised fuels for shipping, initiating a trend towards hydrogen-based fuels such as e-ammonia and e-methanol. In aviation, growing adoption of sustainable aviation fuel due to government quotas and industry pledges will increase hydrogen demand.

Many EU Member States have **national hydrogen strategies** containing electrolysis targets. The targets add up to approximately 35 GW in the EU by 2030, which comes close to the 40 GW target the EU has set itself. Several Member States have not yet published targets.

Key-trends in biomethane and hydrogen in Europe

Green: Confirmed trend
Blue: Emerging trend is developing

Supply

BIOMETHANE

Hydrothermal gasification is expected to reach full industrial scale in 2023–2025

Membrane separation is the dominant upgrading technology covering 35% of biomethane plants today

Biomethane production is growing with a ~13% increase in upgrading plants in 2021

Advanced pretreatment technologies are being developed to increase yield

HYDROGEN

Electrolyser manufacturing moving to industrial scale with Gigafactory announcements totalling over 20 GW/y by 2025

Green hydrogen project pipeline skyrocketing with ~50 GW of green hydrogen capacity planned by 2030

Increasing electrolyser pressure levels and system integration with renewable energy sources

Business case of blue and green hydrogen improving with carbon prices reaching €60/tCO_2 in EU ETS

Steep cost reductions of around 36% for green hydrogen expected in coming years – to 2.5 €/kg by 2025

Infrastructure

Number of biogas pooling projects are increasing, driven by more favourable commercial and policy factors

Initial commercial deployment of reverse flow facilities, with 15 in operation and 25 under construction across the EU

Hydrogen transport infrastructure and storage deployment accelerating with several IPCEIs

Efficient large scale hydrogen compression to become available in coming years

Demand

BIOMETHANE

Increased deployment of bio-CNG and bio-LNG in road and maritime transport

Industry is seeking to tap into the 310 Mt/year biogenic CO_2 potential to achieve negative emissions

Biomethane is replacing natural gas in hard-to-electrify industries such as chemicals, steel, and food and beverages

HYDROGEN

Emerging demand for hydrogen-based e-fuels in shipping and aviation, possibly leading to around 90 TWh hydrogen demand by 2030

Proposed mandate of 50% green hydrogen share in industry by 2030 in Fit-for-55 package will lead to a guaranteed green hydrogen demand

Transition to hydrogen-based steelmaking accelerating, possibly leading to around 80 TWh hydrogen demand by 2030

GAS FOR CLIMATE
A path to 2050

Source: Gas for Climate consortium, 2020. Supported by Guidehouse

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1. Introduction

As announced in the European Green Deal, the European Union (EU) aims to fully decarbonise its economy by 2050, which requires a complete overhaul of the energy system and its infrastructure. By 2030, the EU is targeting a 55% reduction in greenhouse gas (GHG) emissions compared to 1990 levels. The Fit for 55 proposals, released in July 2021 by the European Commission (EC), are intended to enable the necessary acceleration of GHG emission reductions in the next decade. Raising the ambitions of EU climate policy will require significant investment in energy efficiency, renewable energy, new low-carbon technologies, and grid infrastructure. It will also necessitate the close integration of the electricity and gas sectors and their respective infrastructures. A decarbonised Europe will be based on an interplay between the production of renewable electricity and renewable and low-carbon gases to transport, store, and supply all sectors with renewable energy at the lowest possible costs.

In a series of reports over the past few years, the Gas for Climate consortium showed that renewable and low-carbon gases have an important role to play in the EU energy system and that existing gas infrastructure and knowledge can support the transition to an energy system with net-zero CO_2 emissions at the lowest societal cost. The Gas for Climate vision and pathways towards 2050 cover all energy-intensive economic sectors and demonstrate, along with the crucial role of renewable and low-carbon gases, that current policies and trends are not yet sufficient to realise Europe's climate ambitions for 2030 and 2050 (see Box 1). Policy and market actions are required to speed up the transition, and progress of necessary developments must be closely monitored to ensure the transition is achieved at the lowest societal costs.

Renewable and low-carbon hydrogen and biomethane developments attract a lot of positive attention in the media, both in discussions of new policies and in company strategies. To better track the current market state of deployment and trends towards further scale up and cost reductions, Gas for Climate published a comprehensive overview in December 2020. The 2020 market state and trends report provided an overview to policymakers, energy users and producers, equipment manufacturers, and infrastructure companies. This 2021 edition is an addition highlighting the most recent market developments of the past ten months for biomethane and hydrogen. While the transformation towards net-zero CO_2 emissions is multifaceted and consists of many interlinked market and technological developments, the main focus of the analysis is on key trends in sectors and subsectors most promising in the early 2020s-2030, as identified in the pathways study.[1] This report is structured in four chapters that analyse the market state and trends of biomethane (Chapter 2) and green and blue hydrogen supply (Chapter 3), provide an overview of showcase projects (Chapter 4), and EU and national strategies for biomethane and hydrogen (Chapter 5).

1 Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, prepared for Gas for Climate, April 2020, https://gasforclimate2050.eu/wp-content/uploads/2020/04/Gas-for-Climate-Gas-Decarbonisation-Pathways-2020-2050.pdf.

Box 1. Gas for Climate

In June 2017, a group of European gas transmission system operators (TSOs) and biogas associations convened to explore the future role and value of gas and gas infrastructure in a fully integrated and decarbonised EU energy system. This group became the Gas for Climate initiative. Gas for Climate is committed to achieving net-zero GHG emissions in the EU by 2050, mainly through renewable energy. The group sees a vital role for existing gas infrastructure to the transport, storage, and distribution of biomethane and hydrogen in combination with a large increase in renewable electricity. The group consists of 11 TSOs (DESFA, Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, Nordion Energi, ONTRAS, OGE, Snam and Teréga,) and two biomethane associations (European Biogas Association and Consorzio Italiano Biogas). Members are based in nine EU Member States.

In April 2020, Gas for Climate launched the *Gas Decarbonisation Pathways 2020-2050* study, analysing the transition towards the lowest cost climate-neutral system by 2050. This study developed gas decarbonisation pathways from 2020 to 2050, and identified what investments and actions are needed across the energy system. The central pathway in this study achieves the 2050 Optimised Gas end state, as first analysed in the 2019 Gas for Climate study titled *The optimal role for gas in a net-zero emissions energy system*. The *Gas Decarbonisation Pathways 2020-2050* study highlights that additional EU climate and energy policies are needed to position Europe on the road to net-zero by 2050. Its central and aspirational Accelerated Decarbonisation Pathway examines which investments and innovations need to occur to achieve a 2030 GHG reduction target of 55% and climate neutrality by 2050. The European Green Deal can facilitate these developments by accelerating emissions reductions, creating sustainable EU jobs, and creating first-mover advantages for EU industry by:

- Adapting the EU policy framework to make gas infrastructure future-proof in an integrated energy system and a key asset for the sustainable and cost-efficient decarbonisation of the EU economy.
- Stimulating the supply of biomethane and hydrogen through a binding mandate for 10% gas from renewable sources by 2030.
- Fostering cross-border trade and transport of hydrogen and biomethane and clarifying market rules for green and blue hydrogen, including for hydrogen transport.
- Incentivising demand for hydrogen and biomethane and producing dispatchable electricity by strengthening and broadening the EU emissions trading system (ETS) with targeted and time-bound contracts for difference.

2. Biomethane trends

Key takeaways

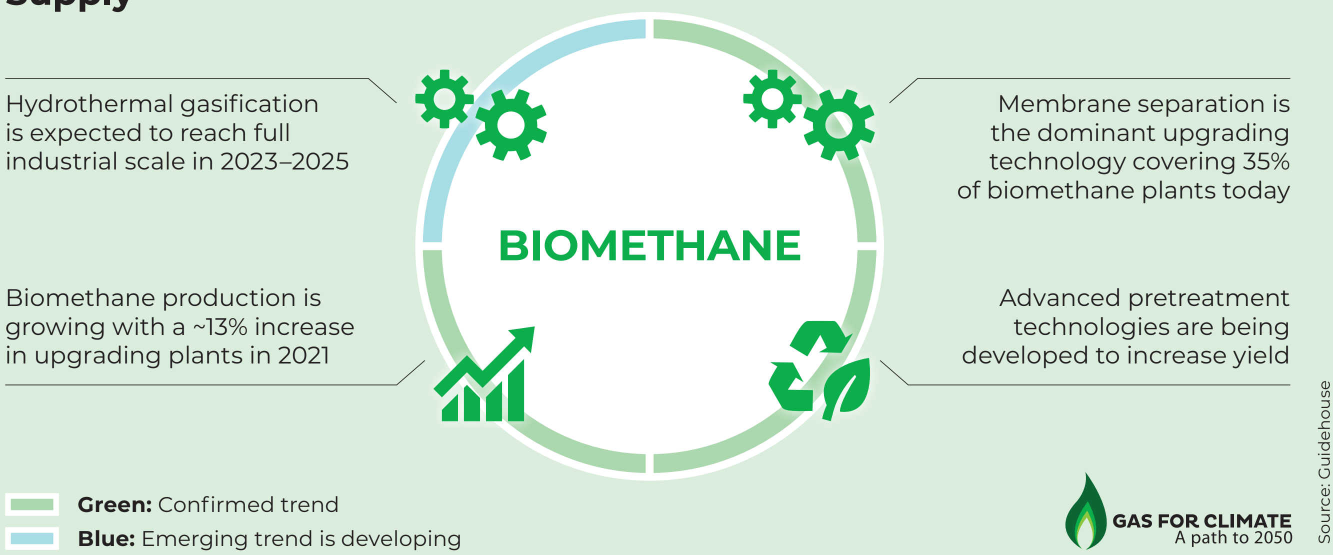
- **Biomethane production** is growing in Europe. In 2020, 32 TWh of biomethane was produced. As of August 2021, 992 upgrading plants are in operation (+13% in 2021 so far). France continues to increase its biomethane production with 306 upgrading plants in service; it is now ahead of Germany, which has 242 upgrading plants in operation.
- **New pretreatments for feedstocks** are being developed and used at an industrial scale to increase the biogas and biomethane yield by unlocking additional feedstocks like lignocellulose and woody biomass. These materials need to undergo pretreatment to be biodegraded in the anaerobic digestion process.
- **Anaerobic digestion** is still the most commonly used biogas production method (90%). **Hydrothermal gasification** is reaching its next phase, with full industrial scale expected in 2023-2025.
- The **gas infrastructure** in currently six countries has been upgraded or is planned to better match the rising decentralised biomethane production. In total, 15 reverse flow facilities are in service in Denmark, France, Germany, and the Netherlands and 25 are under construction (Denmark, France, Belgium). Furthermore, 16 feasibility studies have been announced (France, Italy).
- **Biomethane, bio-liquified natural gas (LNG), and bio-compressed natural gas (CNG) demand** continues to grow in the industry and transport sectors to replace fossil-based alternatives as a climate-neutral energy carrier or feedstock.
- As fossil fuel prices increase, **biogenic CO_2** (captured from biomethane production) becomes a more valuable climate-neutral feedstock; biogenic CO_2 is being used in the industry sector to replace fossil-based CO_2.

Biomethane (CH_4) is produced by upgrading biogas, which contains next to around 60% biomethane, a share of (biogenic) CO_2 of around 40% - dependent on the feedstock used to produce biogas. This chapter highlights current developments in biomethane supply, infrastructure, and demand.

2.1 Supply

According to International Energy Agency (IEA), the overall production potential for biomethane in Europe is 1,350 TWh due to the high availability of biodegradable feedstock.[2] Additionally, the production of biomethane is growing. Next to plant numbers and sizes, this section discusses developments in production technologies, feedstock pretreatments, and biogas upgrading.

Supply



2.1.1 Number of biomethane plants increasing

In 2020, the number of biomethane plants in Europe increased to 880 upgrading plants. These plants collectively produced 32 TWh of biomethane in 2020. As of August 2021, **992 upgrading plants** are in operation.[3] However, the development differs significantly between countries, mainly driven by the national strategies and financial support mechanisms provided (described in Chapter 5).

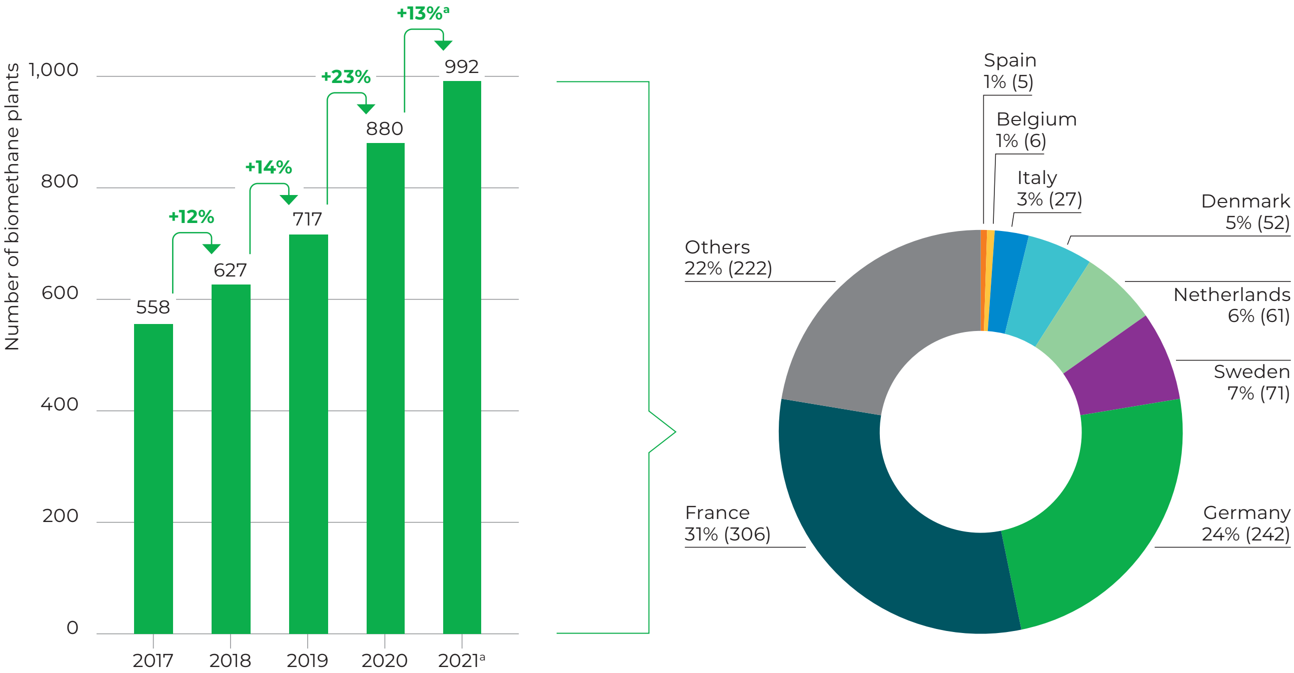
Figure 1 shows the development in number of biomethane plants. In 2020, 91 new plants were installed, and as of August 2021, 92 new biomethane plants started operating in Europe.[4] France has seen the largest growth in biomethane plants in recent years from 45 to 306 plants, representing an average annual growth rate of 60% from 2017 up to 2021. France now has the most biomethane plants in Europe, surpassing Germany (306 facilities as of end August 2021).

2 IEA, *Outlook for biogas and biomethane: Prospects for organic growth* (report extract), March 2020, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/the-outlook-for-biogas-and-biomethane-to-2040.

3 European Biogas Association (EBA), EBA Statistical Report 2021

4 Open Data, “Active Biogas Injection sites in France,” accessed 11th August 2021, https://opendata.reseaux-energies.fr/explore/dataset/points-dinjection-de-biomethane-en-france/export/?disjunctive.site&disjunctive.departement&disjunctive.region&disjunctive.type_de_reseau&disjunctive.grx_demandeur&sort=-date_de_mes&disjunctive.nom_epci.

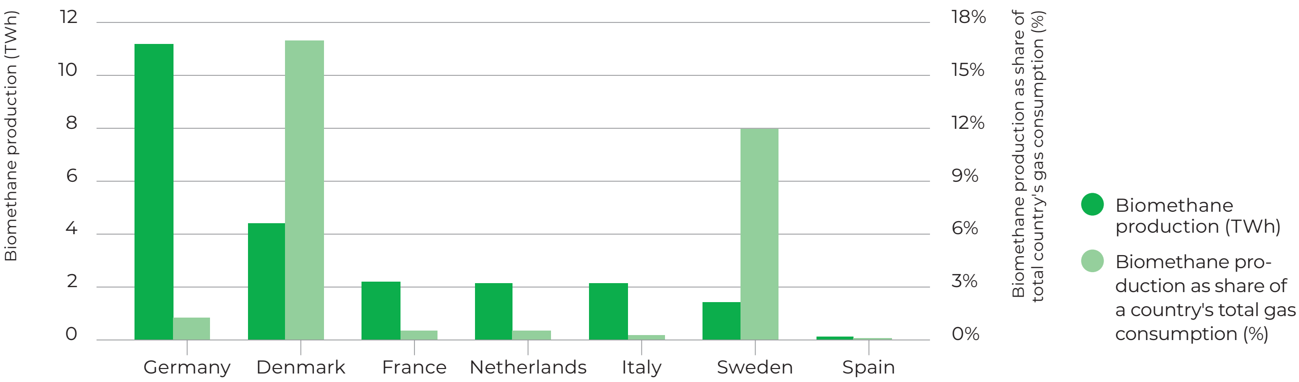
Figure 1
Number of biomethane plants in Europe (EBA)[5]



a 2021 includes plants that have started until 08-09/2021, subject to the data availability of each country.

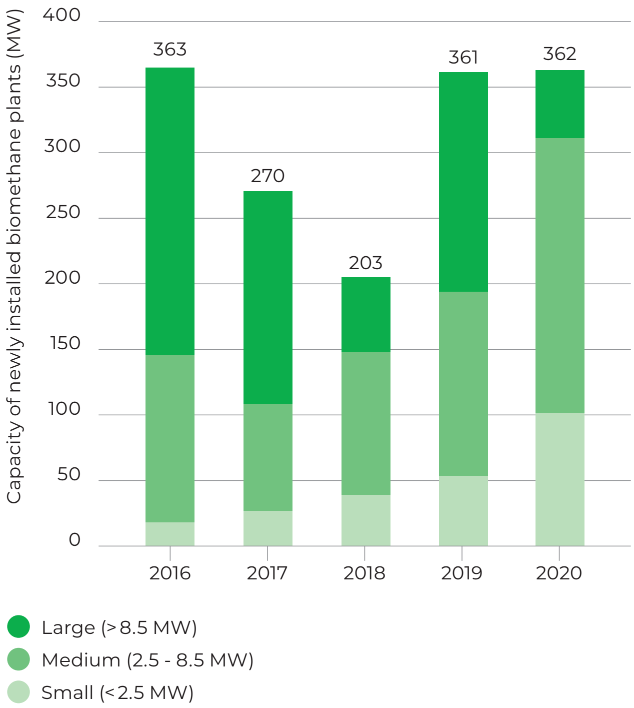
The **produced biomethane in 2020 differs strongly by country**, as illustrated in Figure 2. Germany produced the most biomethane (11 TWh). France, with the most biomethane plants in Europe in 2020, produced 2 TWh of biomethane. Denmark, which has fewer plants, produced 4 TWh, meaning the average plant size is different in these countries, while also some plants came into operation late in the year in France. The **share of produced biomethane compared to the total gas use also varies considerably by country**. In most countries in 2020, the share is at 1 % or lower, whereas it is 12% or greater in Denmark and Sweden.

Figure 2
Biomethane production (TWh) and relative share for selected European countries in 2020[5]



5 European Biogas Association (EBA), EBA Statistical Report 2021

Figure 3
Size of newly installed biomethane plants in MW (EBA, FNR)[6, 7]



There is a trend towards small-scale biomethane plants mostly driven by France, as Figure 3 shows. In 2020, fewer large-scale plants (>8.5 MW) and more small-scale (<2.5 MW) upgrading plants were installed than in the previous year. This development shows that upgrading biogas to biomethane is becoming more economically feasible, even in small-scale projects.

2.1.2 Hydrothermal gasification on the verge of commercialisation

Hydrothermal gasification is poised to scale up in the coming years. Anaerobic Digestion (AD) combined with upgrading is still the most commonly deployed technology to produce biomethane. In 2018, 90% of the produced biomethane globally came from AD.[8] In this process, the organic feedstock is broken down by microorganisms to produce biogas and digestate. The biogas can be used directly in a combined heat and power (CHP) plant or otherwise upgraded to biomethane. The digestate is commonly used as high quality fertiliser.[8] While AD is a mature technology,[9] there are still developments in feedstock pretreatment for AD (see Chapter 2.1.3).

Next to AD, biomethane can also be produced using gasification, using two main technologies:

1. **Thermal gasification** uses dry woody and lignocellulose biomass as feedstock. With a controlled amount of oxygen and steam at high temperatures, the feedstock is thermally broken down into syngas (CO, CO_2, H_2) and biochar. This syngas is cleaned and converted into biomethane in a catalytic reaction or in the future using biological processes. Afterwards, a gas upgrading step is necessary to remove CO_2, water, and pollutants. This process is still in the early commercial phase[8].
2. **Hydrothermal gasification** converts dry and wet raw biomass into syngas, which is further processed into biomethane. In this gasification process, the biomass is heated and compressed until the containing water reaches the supercritical phase (temperature: >374°C, pressure: >221 bar). In this phase, the water becomes reactive and forms a methane-rich syngas by reacting with the organic carbon of the biomass. Additional gas cleaning is necessary to upgrade biomethane to a sufficient quality.[10] Hydrothermal gasification is on the verge of commercialisation and, according to GRTgaz and ENTSO-G, **industrial scale will be reached by 2023-2025**.[11]

6 European Biogas Association (EBA), EBA Statistical Report 2021
7 FNR, “Figures of thumb,” accessed 21st October 2021, https://biogas.fnr.de/daten-und-fakten/faustzahlen.
8 IEA, *Outlook for biogas and biomethane: Prospects for organic growth*, (report extract) March 2020, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane.
9 Guidehouse Insights, *Renewable Natural Gas: Overview of the Current State of the Biogas and Renewable Natural Gas Markets*, 1Q 2020, https://guidehouseinsights.com/reports/renewable-natural-gas.
10 Guidehouse, *Market state and trends in renewable and low-carbon gases in Europe*, prepared for Gas for Climate, December 2020. https://gasforclimate2050.eu/wp-content/uploads/2020/12/Gas-for-Climate-Market-State-and-Trends-report-2020.pdf.
11 ENTSOG, “Innovative Projects Platform – Technology,” accessed 29th September 2021, https://www.entsog.eu/technology.

There are already several hydrothermal gasification demonstration plants, such as:

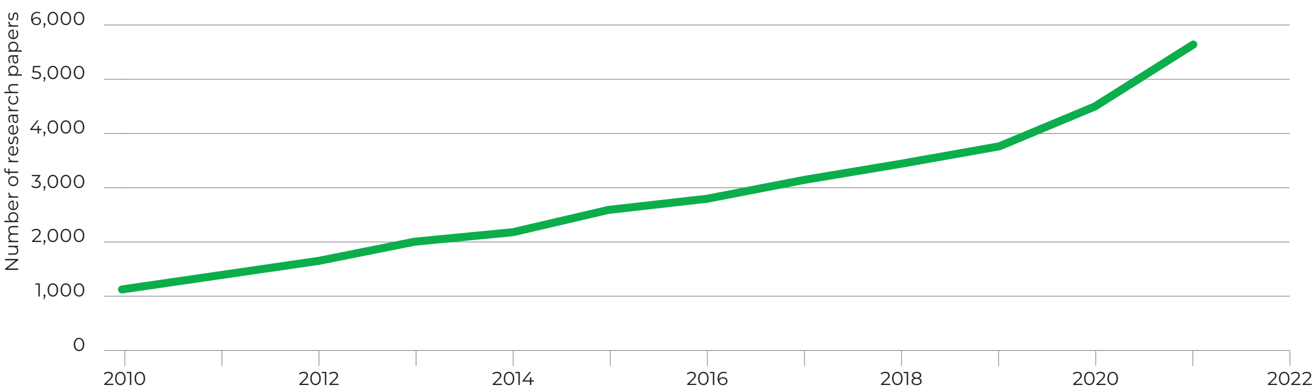
- In Alkmaar, the Netherlands, by 2023, 5 GWh/year of biomethane will be produced, which could be further expanded to 5 TWh/year.[12]
- In Gaya, France, 30-40 m^3/h (300-400 kWh) of biomethane has been produced from dry biomass (e.g., wood, straw) in a 600 kW_{th} gasifier since 2020.[13]
- Based on this demonstration plant in Gaya, a large-scale project in Le Havre is being evaluated that would include a 20 MW_{th} gasifier producing 150 GWh/year of biomethane.[14, 15, 16]

2.1.3 Advanced pretreatments evolving to unlock additional feedstocks

Advanced pretreatment technologies are under development to enable a wider range of feedstocks to be used in AD; this is an important way to increase the potential for biogas and biomethane production. The pretreatment is either physical, chemical, biological, or a combined process. The aim is to grow the volumes of biogas produced through AD by using additional feedstocks like lignocellulose substrates, straw, and woody materials; the use of these materials is currently limited in an anaerobic digester because they cannot be easily biodegraded. Pretreatments can also improve the efficiency of the AD process by increasing yield[17] and providing new possibilities for automation or faster digestion. Faster digestion leads to lower retentions times which enables the use of smaller reactors and will thus lower investment costs.[18]

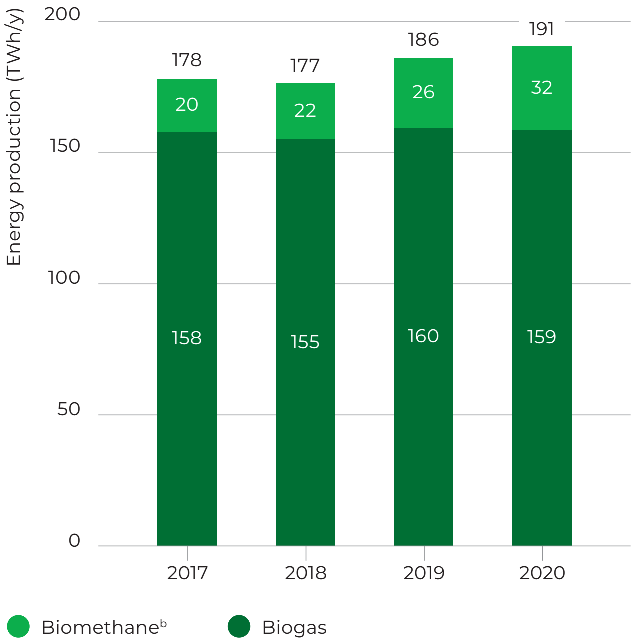
The rising interest in pretreatments is reflected in the growing number of research papers on the topic, as Figure 4 shows. This trend in the academic research is already seen in industrial biogas plants. Various AD plants are using feedstocks they were previously unable to process. For example, in the Tortona ECO-Project (Italy), lignocellulosic material is used to produce 2.8 million m^3 of biomethane per year for grid injection. This could supply 2,100 CNG cars for 1 year.[19] In 2019, a biomethane plant in Schwedt/Oder, Germany, reached its full scale of 16.5 MW of biomethane production capacity using 100% straw. This could cover the annual fuel demand of 20,000 CNG cars.[20]

Figure 4
Number of research papers on biomass pretreatments (Elsevier)



12 Gasunie, "Supercritical water gasification," accessed 14th October 2021, https://www.gasunie.nl/en/expertise/green-gas/supercritical-water-gasification.
13 Gaya, "When wood and straw residue is turned into 100% renewable green gas," accessed 21st October 2021, https://www.projetgaya.com/en/a-sizeable-project-and-energy-for-the-future/.
14 Gaya, "When wood and straw residue is turned into 100% renewable green gas."
15 IEA Bioenergy, *Emerging Gasification Technologies for Waste & Biomass*, December 2020, https://www.ieabioenergy.com/wp-content/uploads/2021/02/Emerging-Gasification-Technologies_final.pdf.
16 Sherrard, A., "Project Gaya Passes Historic Milestone," *Bioenergy International*, No. 115, January 2021, https://online.fliphtml5.com/zxhnr/ubvr/#p=20.
17 Abraham, A. et al., "Pretreatment strategies for enhanced biogas production from lignocellulosic biomass," Bioresource Technology, vol. 301, April 2020, https://www.sciencedirect.com/science/article/pii/S0960852419319546.
18 Ecofys, *Innovation Needs Assessment for Biomass Heat*, 22 January 2018, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699669/BE2_Innovation_Needs_Final_report_Jan18.pdf.
19 Snam, "Tortona eco-project," accessed 15th October 2021, https://www.snam.it/it/snam4environment/impianti/ecoprogetto_tortona.html.
20 VerbioGas, "Experience the future today," accessed 15th October 2021, https://www.verbiogas.de/verbiogas/.

Figure 5
Biogas and biomethane production in TWh in Europe (EBA)[21]



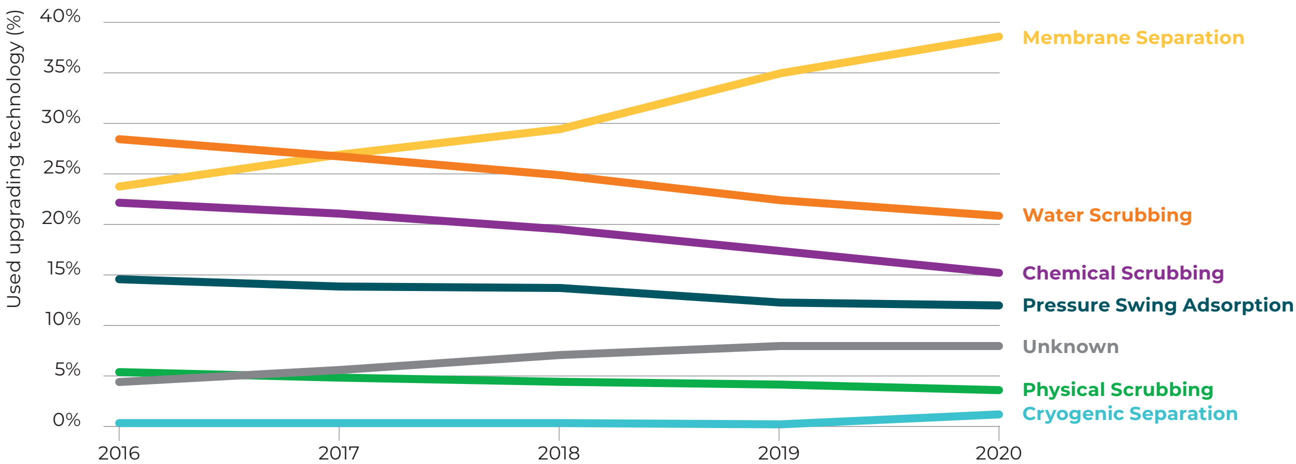
b Only includes biomethane from Anaerobic Digestion (AD) and not from gasification.

2.1.4 Biogas upgrading increasing, using membrane separation

The current trend shows that most newly built biogas plants are combined with an upgrading technology to produce biomethane. Figure 5 illustrates that the production of biogas is stagnant whereas biomethane production is growing, underlining the stated trend. Hence, the upgrading technology is becoming more important to increase the production of grid-quality biomethane.

Figure 6 shows an overview of the upgrading technologies. **Membrane separation** is still the most used upgrading technology—more than 35% of biomethane plants use this technology. The use of **cryogenic separation** is in early development with 11 new plants in 2020[21]. This upgrading mechanism is based on cooling down the biogas, resulting in liquid CO_2 and gaseous methane. The still gaseous methane (higher boiling temperature) can either be cooled down further to produce bio-LNG or can be used as biomethane. Bio-LNG is increasingly produced in this process because the cooling energy demand in cryogenic separation is high, decreasing the additional cooling demand for the liquefaction of biomethane.

Figure 6
Used upgrading technology in biomethane plants (EBA)[21]



21 European Biogas Association (EBA), EBA Statistical Report 2021

The main advantage of liquefication to **bio-LNG and liquified biogenic CO_2 is a much higher density which also allows for easier transportation**. The biogenic CO_2 can either be utilised (carbon capture and utilisation, or CCU) in, for example, the production of e-fuels or the food & beverage industry, or stored (carbon capture and storage, or CCS).

Biogas contains around 60% methane and 40% CO_2 (depending on the feedstock used). To increase the biomethane yield out of the raw biogas, the biogas could be enriched with hydrogen. Two different methods are being tested in a **pilot project** from Aarhus University in Denmark:

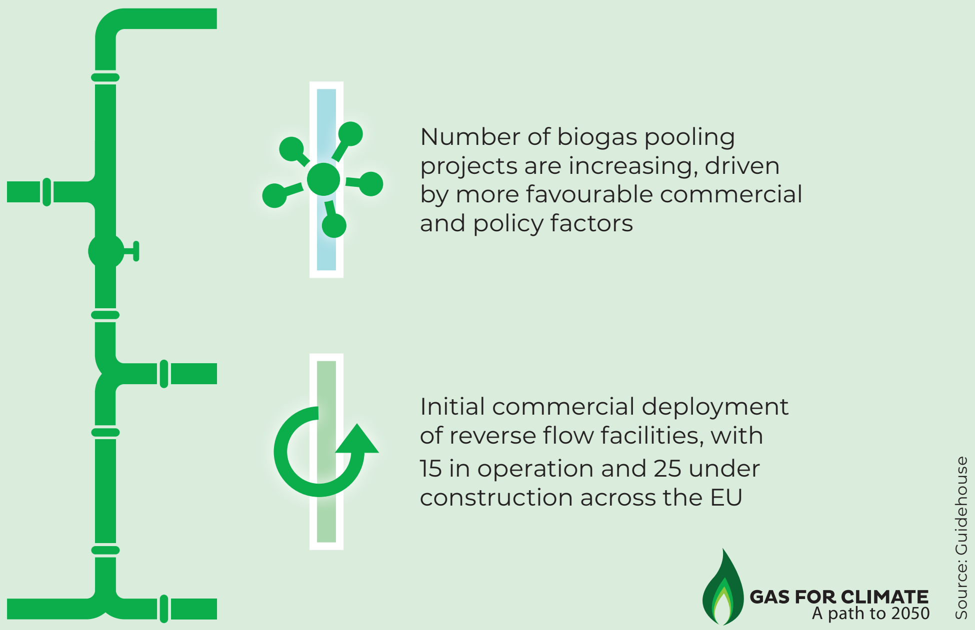
1. **Hydrogen is added directly to the biogas reactor**: the hydrogen influences the biological process in AD, meaning less CO_2 but more biomethane is produced. The biomethane concentration can be elevated to 95% (grid quality) through the additional hydrogen.[22]
2. **Post-treatment of biogas in a Sabatier reactor**: in a high temperature, exothermic, catalytic process, the CO_2 in the raw biogas is converted to biomethane, increasing the biomethane yield. This upgrading method leads to grid-quality biomethane.[23]

According to the EBA, the first large-scale project to enrich biogas with hydrogen is expected to be operational in the next 2 years, and further scale up in the next 3 to 5 years.

2.2 Infrastructure

In contrast to biogas or hydrogen, biomethane can be injected in the current natural gas grid without any retrofitting. However, biomethane production is more decentralised than the current natural gas supply because it is closely linked to rural biomass production. The current top-down structure of the gas grid is not always the best suited solution to increase the share of biomethane. Reverse flow facilities are being put in place to allow gas transportation from the distribution to the transmission grid, so more biomethane can be injected into local distribution grids. Infrastructure projects (e.g., biogas pooling) for biogas transportation are being implemented since biogas is not suitable to be injected into the natural gas grid due to its high share of CO_2.

Infrastructure



Green: Confirmed trend

Blue: Emerging trend is developing

22 Maegaard, K. et al., "Biogas upgrading with hydrogenotrophic methanogenic biofilms," Bioresource Technology, vol. 287, September 2019, https://www.sciencedirect.com/science/article/pii/S0960852419306522?via%3Dihub.

23 Dannesboe, Christian, "Synergy Between Biogas Upgrade and SOEC," Skandinaviens Biogaskonference 2017, presented on 7 November 2017, https://pure.au.dk/portal/files/121739324/Presentation_Skive_Skandinaviens_Biogaskonference_2017.pdf.

2.2.1 Biogas pooling makes biomethane upgrading more economical

One major infrastructure development is biogas pooling, which is still in the early development phase, as stated in the 2020 market state and trends report[24]. Biogas pooling is a system where small- to medium-sized biogas plants are connected via biogas pipelines to one large biomethane upgrading facility. This makes biomethane production more economical as grid connection costs are reduced.[24]

The number of biogas pooling projects are expected to increase in the coming years as subsidies for older biogas plants come to an end, for instance after 20 years in Denmark or after 12 years in the Netherlands[25]. Due to the good crediting possibilities of slurry/manure biogas in the transport sector after the amendment of the Renewable Energy Directive II (RED II), the business case of biomethane upgrading is improving. It is expected that EU Member States, following the above-mentioned amendment, will increasingly fund biomethane.[26] Existing examples include the feed-in premium in Denmark[27] and the Netherlands (see Chapter 5).[28]

2.2.2 Increasing deployment of reverse flow facilities

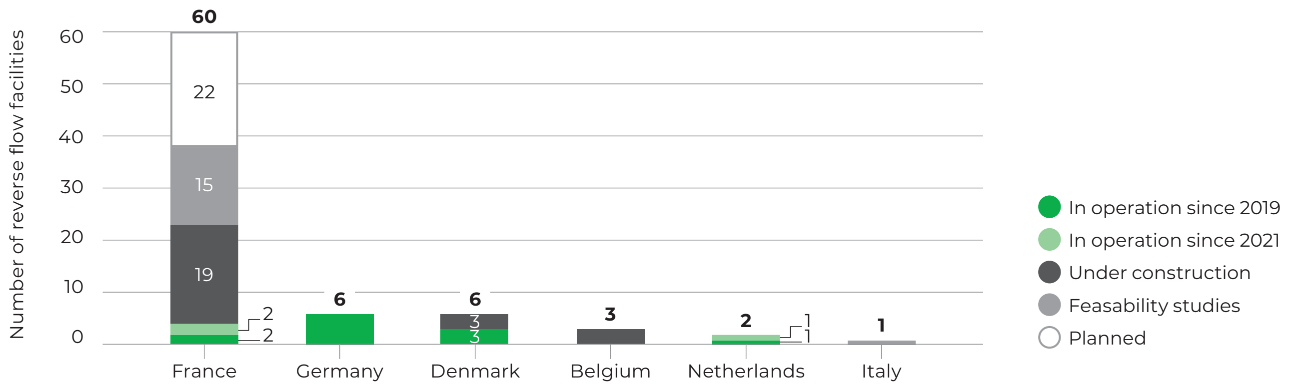
Currently, **47% of biomethane plants are connected to the distribution grid**.[29] This decentralised biomethane injection is different to the centralised large-scale natural gas transmission grid injection. In some countries, the present top-down structure from the transmission to the distribution grid is adjusted by installing reverse flow facilities.

Reverse flow facilities are located at the intersection of the transmission grid and the distribution grid **and allow for physical flows from the distribution to the transmission grid**. If too much biomethane is injected into the low pressure distribution grid, the biomethane is compressed and injected into the high pressure transmission grid.[30] This ensures more flexibility for the gas system and **expands the possibility for decentralised biomethane injection**.

Reverse flow is still in early commercial deployment, but the number of plants is growing, as can be seen in Figure 7. 15 reverse flow facilities are in operation across the EU and 25 are under construction - of which 75% in France, where also 15 feasibility studies have been announced. The number of facilities is expected to accelerate in the coming years.

24 Guidehouse, *Market state and trends in renewable and low-carbon gases in Europe*, prepared for Gas for Climate, December 2020. https://gasforclimate2050.eu/wp-content/uploads/2020/12/Gas-for-Climate-Market-State-and-Trends-report-2020.pdf.
25 Renewable Gas Trade Centre in Europe (REGATRACE), *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.
26 Umweltbundesamt, *Options for existing biogas plants by 2030 from an economic and energy point of view*, 2020, https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2020-01-30_texte_24-2020_biogas2030.pdf
27 Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), *Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy*, Ifri, April 2019, https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf.
28 Netherlands Enterprise Agency, *SDE++ 2020: Stimulation of Sustainable Energy Production and Climate Transition*, November 2020, https://english.rvo.nl/sites/default/files/2020/11/Brochure%20SDE%20plus%20plus%202020.pdf.
29 European Biogas Association (EBA), EBA Statistical Report 2021
30 Guidehouse, *Market state and trends in renewable and low-carbon gases in Europe*, prepared for Gas for Climate, December 2020. https://gasforclimate2050.eu/wp-content/uploads/2020/12/Gas-for-Climate-Market-State-and-Trends-report-2020.pdf.

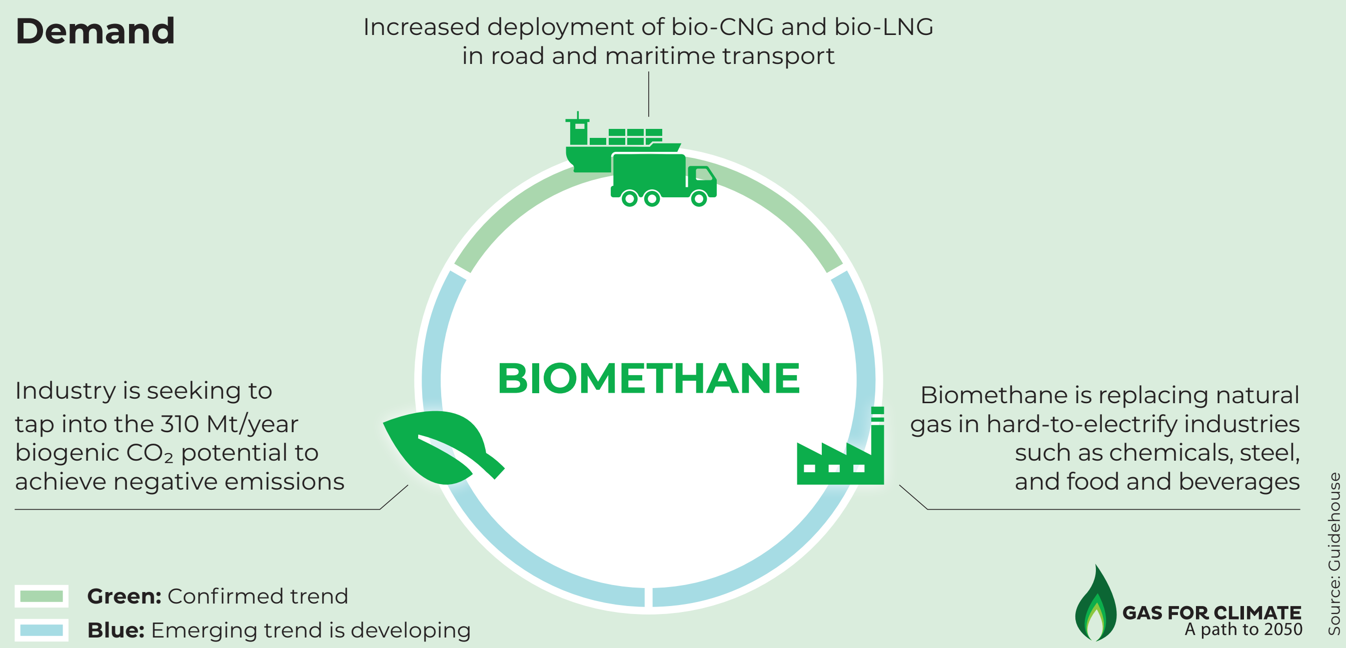
Figure 7
Number of reverse flow facilities in selected European countries (TSO interviews, ENTSOG)[31, 32, 33]



Gas transmission and distribution networks are structured differently across Europe, so reverse flow facilities are not always necessary. This is true for more interconnected distribution grids when biomethane can be injected into the grid without any need to compress for the transport in the transmission grid.

2.3 Demand

In the following sections the trends in biomethane demand are highlighted. Key trends are seen in hard-to-electrify industries. Biogenic CO_2 demand is rising, too. In the transport sector bio-CNG and bio-LNG demand grows.



31 GRTgaz, "32 reverse flow projects : GRTgaz steps up its plans to accommodate biomethane from the regions," 4 August 2021, https://www.grtgaz.com/en/medias/press-releases/32-reverse-flow-projects.

32 Authority for the Regulation of Energy Networks and the Environment (ARERA), *Gas Transport and Distribution Networks Natural: Pilot Projects for the Optimization of the Innovative Management and Use*, 11 February 2020, https://www.arera.it/allegati/docs/20/039-20.pdf (10.4)

33 ENTSOG, "6. Energy Transition Projects," *Ten-Year Network Development Plan 2020, Infrastructure Report*, https://tyndp2020.entsog.eu/infrastructure/energy-transition-projects/.

Global and **European biomethane demand is growing**. The main reason are incentives to reduce GHG emissions by using renewable gases such as biomethane instead of fossil gas.[34]

In 2018, the IEA estimated overall biomethane demand was 23 TWh in Europe. This demand was mainly driven by high temperature industrial processes, the chemical industry, heavy duty transport, and maritime shipping. The IEA expects rising biomethane demand for Europe, shown in Figure 8. Its two scenarios, different in ambition level, forecast a continuous biomethane demand growth until 2040.

- Based on 2018 biomethane support policies, the **European demand in 2040 is expected to grow to 140 TWh**.
- Based on a sustainable development scenario designed to achieve energy-related sustainability goals, the estimated **biomethane demand is 419 TWh in 2040**.[34]

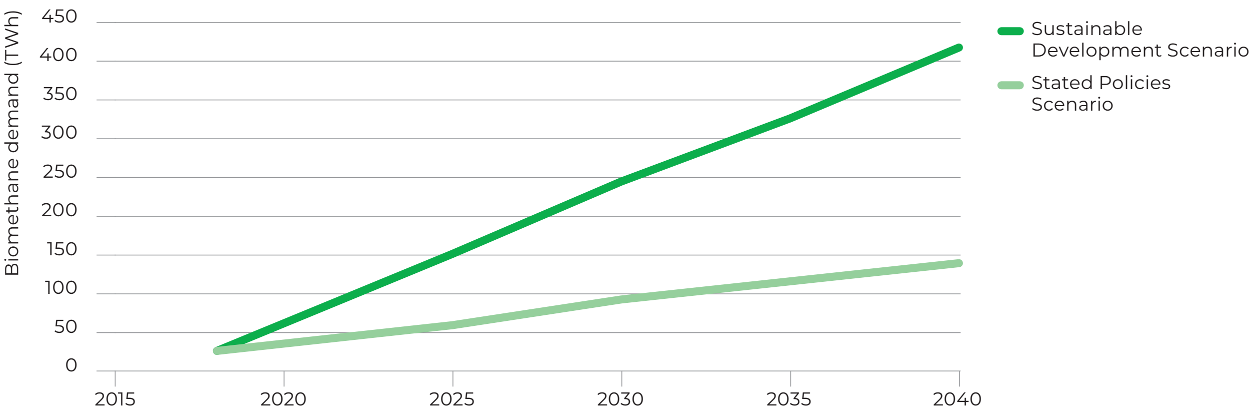
The IEA estimates an overall European production potential for biomethane of 1,350 TWh, which is much higher than the estimated demand in 2040; this indicates there is significantly more potential for the sector to grow.[34]

2.3.1 Biomethane use in hard-to-electrify industries is rising

Biomethane is replacing natural gas in hard-to-electrify industries such as chemicals, steel, and food and beverages. Biomethane is particularly sought after in industry because bio-based fuels do not incur carbon costs under the EU ETS. Biomethane can also replace existing natural gas-based processes without additional investments in new technologies.

Biomethane is used as feedstock for high temperature heat purposes or in cogeneration of electricity and heat. As biomethane can be transported via the gas grid, CHP plants powered with biomethane can be built in locations with a high demand for both heat and electricity. In contrast, biogas that has not been upgraded to biomethane cannot be transported using the existing natural gas grid due to its high share of CO_2. Hence, biogas is used mainly in rural areas close to production.[35]

Figure 8
Biomethane demand in TWh in Europe in two different scenarios (IEA)[34]



34 IEA, *Outlook for biogas and biomethane: Prospects for organic growth* (report extract), March 2020, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/the-outlook-for-biogas-and-biomethane-to-2040.
35 EBA, "About biogas and biomethane," accessed 25th September 2021, https://www.europeanbiogas.eu/about-biogas-and-bio-methane/.

- In the **chemical industry**, methane is an important feedstock used in fertiliser and methanol production, which could be replaced by biomethane. For example, Perstorp uses biomethane to produce sustainable methanol used in its chemical factories.[36]

- In the **steel industry**, SSAB uses biogas to replace fossil fuels in processes that cannot be electrified or switched to a hydrogen-based technology.[37]

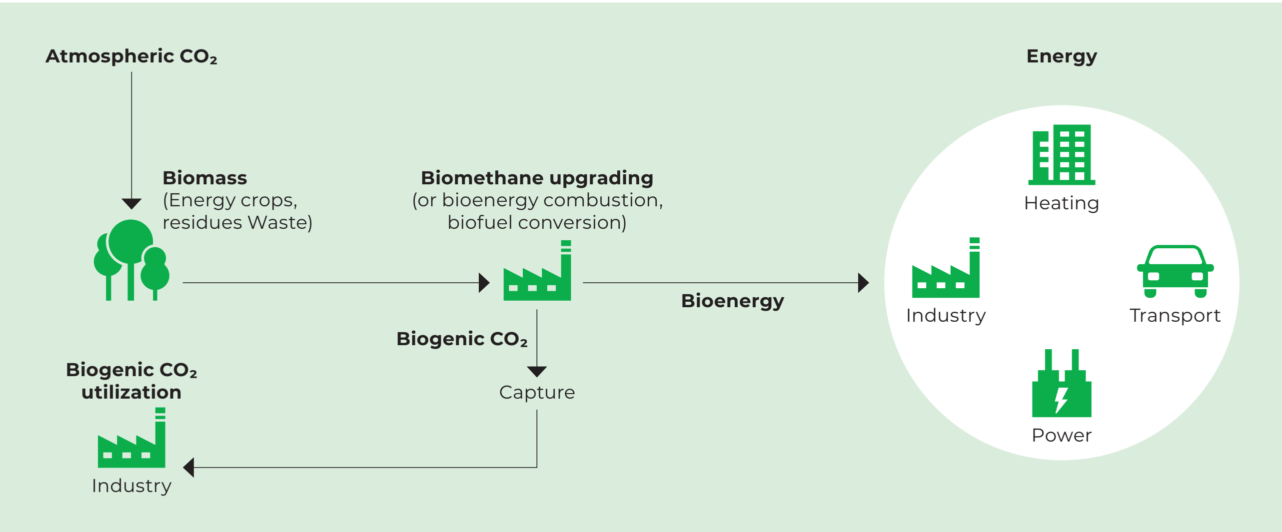
- In the **food industry**, companies like Ferrero plan to substitute the natural gas used in small onsite CHP plants with biomethane from the gas grid. By doing so, they decarbonise their process heat and electricity.[38]

2.3.2 Biogenic CO_2 from biogas increasingly being valorised as high value feedstock in industry and e-fuel production

Upgrading biogas to biomethane with CCU is gaining more attention in industry. CO_2 is used as a feedstock in many industries, and companies are interested in climate-friendly CO_2 sourcing options. Biogenic CO_2 can replace fossil CO_2 and hereby drive the total CO_2 footprint of biogas plants down further. The use of biogenic CO_2 can even lead to negative emissions if the CO_2 is not emitted into the atmosphere. This is the case when the carbon ends up in the final product, in for instance plastics or steel, or when the CO_2 is captured and stored.

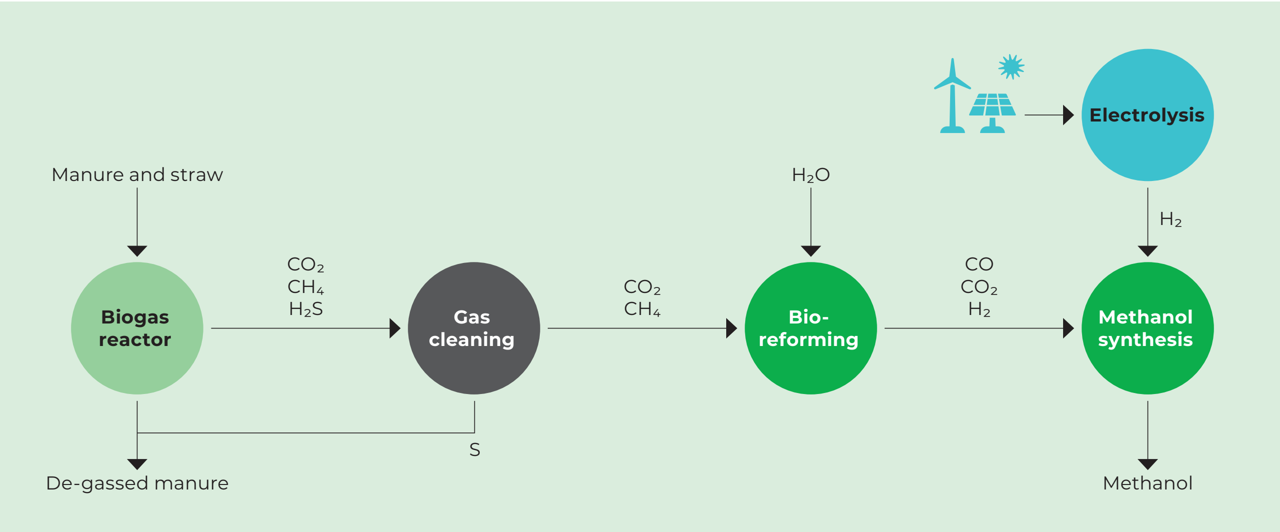
Bioenergy carbon capture and utilisation (BECCU) and storage (BECCS) are **ways to achieve negative emissions**. There are two different methods to capture biogenic CO_2 from biogas:

Figure 9
Path of CO_2 in BECCU (IOGP)[39]



36 Project Air, "What is Project Air?" accessed 29th September 2021, https://projectair.se/en.
37 SSAB, "SSAB has launched an extensive research project in Finland to replace fossil fuels with renewable energy in steelmaking," 15 July 2021, https://www.ssab.com/news/2021/07/ssab-has-launched-an-extensive-research-project-in-finland-to-replace-fossil-fuels-with-renewable-en.
38 Ferrero, *Minimizing environmental impact: Ferrero's corporate social responsibility*, https://www.static.ferrero.com/globalcms/documenti/1614.pdf.
39 IOGP, *The potential for CCS and CCU in Europe. Report to the thirty second meeting of the European Gas Regulatory Forum 5-6 June 2019*, May 2019, https://ec.europa.eu/info/sites/default/files/iogp_-_report_-_ccs_ccu.pdf.

Figure 10
Biomethanol can be produced by syngas generated from biogas (IEA)[43]



1. **Carbon capture during the combustion of biomass (incl. biogas and biomethane) in a CHP plant** from the flue gas. This is commonly referred to as bioenergy carbon capture (BECC).
2. **Carbon capture during the biomethane upgrading process**, where biogas is split into biomethane (CH_4) and CO_2. The CO_2 is captured at relatively low costs due to its high purity. The general principle of BECCU is shown in Figure 9.

Given the high European demand for biogenic CO_2 across industries, it is not stored but utilised. The potential biogenic CO_2 demand for industrial processes is estimated to be 73 Mt/a in Europe.[40] Based on the current biomass combustion, 287 Mt/a CO_2 could be captured from flue gas and 23 Mt/a CO_2 from biogas to biomethane upgrading.[41]

The biogenic CO_2 can be used in the food industry as a heat transfer fluid or for boosting crop yields in greenhouses. Applications where biogenic CO_2 is used as a feedstock include the production of e-fuels, chemicals, or building materials.[42] One example of BECCU is the Korskro biomethane upgrading plant in Denmark, where 16 kt/year of CO_2 are captured to be used in the food and beverage industry (see Chapter 4.1 for more detail).

Biogas can be converted to biomethanol and used in the transport sector or the chemical industry. The conversion process is demonstrated in Figure 10. In a reforming process, the cleaned biogas (CH_4 and CO_2) is mixed with steam to produce syngas (CO, CO_2, H_2). More hydrogen is added to increase the methanol output of the methanol synthesis. To ensure the final product is green methanol, the hydrogen needs to be renewable. The BioReFuel project in Denmark aims to substitute fossil-based methanol with e-fuels.[43] In Sweden, ProjectAir, a development by Perstorp, produces sustainable methanol for the chemical industry (see Chapter 4.1).[44]

40 Patricio, J. et al., "Region prioritization for the development of carbon capture and utilization technologies," Journal of CO_2 Utilization, vol. 17, January 2017, https://www.sciencedirect.com/science/article/pii/S2212982016303389?via%3Dihub.
41 Ericsson, K. "Biogenic carbon dioxide as feedstock for production of chemicals and fuels: A techno-economic assessment with a European perspective," Lund University, September 2017.
42 IEA, *Putting CO_2 to Use: Creating value from emissions* (report extract), September 2019, https://www.iea.org/reports/putting-CO_2-to-use.
43 IEA Bioenergy, "Case Story: Green methanol from biogas in Denmark – a versatile transport fuel," 2020.
44 Project Air, "What is Project Air?" accessed 29th September 2021, https://projectair.se/en.

2.3.3 Increased deployment of bio-CNG and bio-LNG in road and maritime transport

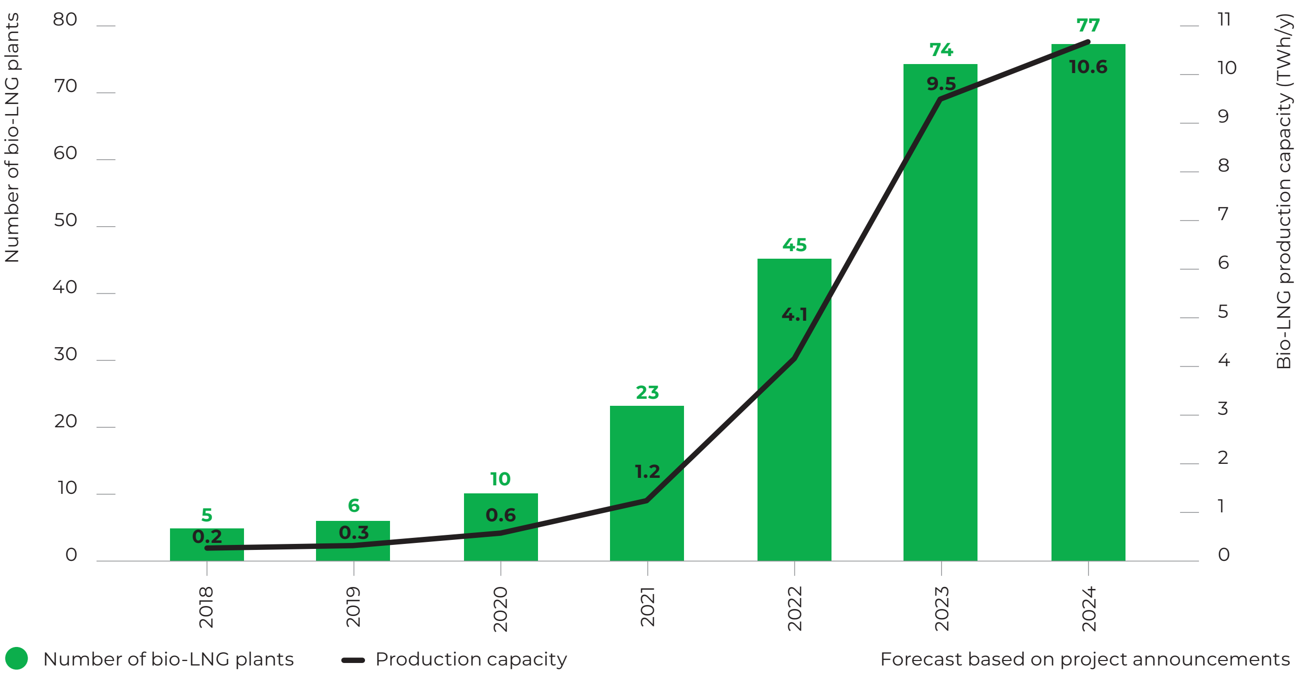
In the transport sector, biomethane is used as bio-CNG in passenger cars and as bio-LNG in heavy duty road and maritime transport. Bio-LNG and bio-CNG have a similar composition to fossil LNG and CNG, so the same infrastructure can be used. Bio-LNG and bio-CNG can be blended at any percentage, which allows a fast upscaling of its use in these sectors to decarbonise them.

The production of bio-LNG is growing rapidly in Europe. Figure 11 shows the fast uptake of bio-LNG plants and the total production capacity. In 2021, the installed capacity is expected to more than double compared to 2020.[45] The future predictions are based on real announcements on a project level. In Italy, 162 t/day of bio-LNG is produced, which equals 0.7 TWh/year.

Bio-CNG is produced onsite at 118 of the 992 biomethane plants in Europe. The leading country is Sweden with 68 onsite bio-CNG production plants. Bio-CNG is often produced in areas without or with a limited gas grid where biomethane must be transported, for example, via fuelling trucks.

The LNG and CNG refuelling infrastructure is developing fast, as Figure 12 shows. In Europe, the number of LNG fuelling stations grew from 332 in 2020 to 438 in 2021. The largest increase in LNG refuelling stations has been in Germany, with 39 new stations in 2021 the total number of stations grew to 71 – an increase of more than 50%. Italy has the most refuelling stations in Europe with 103, up 20% in 2021.[46, 47]

Figure 11
European bio-LNG production capacities in TWh and number of plants (EBA)[45]

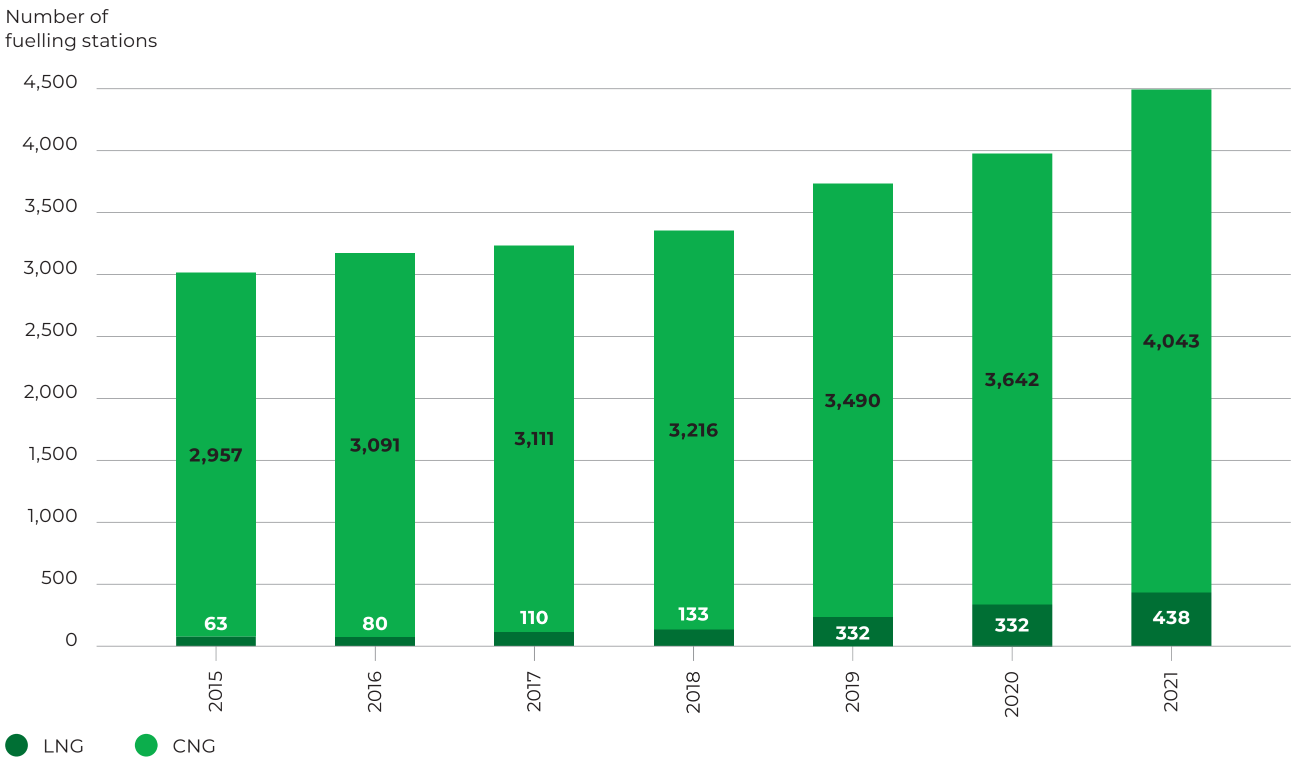


45 European Biogas Association (EBA), EBA Statistical Report 2021
46 EBA, Gas Infrastructure Europe (GIE), The Natural & bio Gas Vehicle Association (NGVA) Europe, SEA-LNG, *BioLNG in Transport: Making Climate Neutrality a Reality*, 2020, https://sea-lng.org/wp-content/uploads/2020/11/BioLNG-in-Transport_Making-Climate-Neutrality-a-Reality_20.11.2020.pdf.
47 NGVA Europe, "Stations map," CNG/LNG Map, accessed 22nd September 2021, https://www.ngva.eu/stations-map/.

The shipping sector is experiencing an increase in the use of bio-LNG. The increase in LNG-fuelled ships allows the blending of bio-LNG, which will further decarbonise the sector. In Frederikshavn, Denmark, a new biogas liquefaction plant by Nature Energy and MAKEEN will become operational in 2023, and produce 0.27 TWh/year of bio-LNG.[49] In November 2020, Total supplied a vessel of shipping company CMA CGM with a 13% blend of bio-LNG, demonstrating the blending possibilities. Multiple projects have been announced on implementing bio-LNG bunkering at large ports across Europe like Marseille[50] and Amsterdam.[51]

Maersk, one of the world's biggest container shipping companies, is leading a discussion on future fuels. Specifically, the discussion focuses on moving away from LNG due to the methane slip[52] to alternative fuels such as bio - or e-methanol and e-ammonia, as will be discussed later in Chapter 3.3.3.

Figure 12
Number of LNG and CNG fuelling stations in Europe (EAFO, NGVA)[48]



48 European Alternative Fuels Observatory, "CNG/LNG refuelling stations (2020)", Alternative Fuels – Natural Gas, European Union, 2020, accessed 22nd September 2021, https://www.eafo.eu/alternative-fuels/ng-natural-gas/filling-stations-stats.
49 Berry, R., "Europe: New Danish plant to produce liquefied biogas for shipping," Petrospot, 24 September 2021, https://www.bunkerspot.com/europe/54325-europe-new-danish-plant-to-produce-liquefied-biogas-for-shipping.
50 TotalEnergies, "Energy transition in shipping: First BioLNG production project at a French port," 5 July 2021, https://totalenergies.com/media/news/press-releases/energy-transition-shipping-first-biolng-production-project-french-port.
51 LNG Prime staff, "Work progresses on first Dutch bio-LNG facility," 13 May 2021, https://lngprime.com/lng-vehicles/work-progresses-on-first-dutch-bio-lng-facility/19782/.
52 LNG has lower downstream emissions than diesel or Heavy Fuel Oil (HFO), but the GHG emissions of the total fuel chain could be higher according to International Council on Clean Transportation (ICCT). The main reason for this is methane slip, which is a more potent GHG—global warming potential (GWP) of 30 times CO_2 on a 100-year timeframe, 85 times on a 20-year timeframe). (ICCT – https://theicct.org/blog/staff/lng-trucks-bridge-nowhere, https://theicct.org/publications/climate-impacts-LNG-marine-fuel-2020)

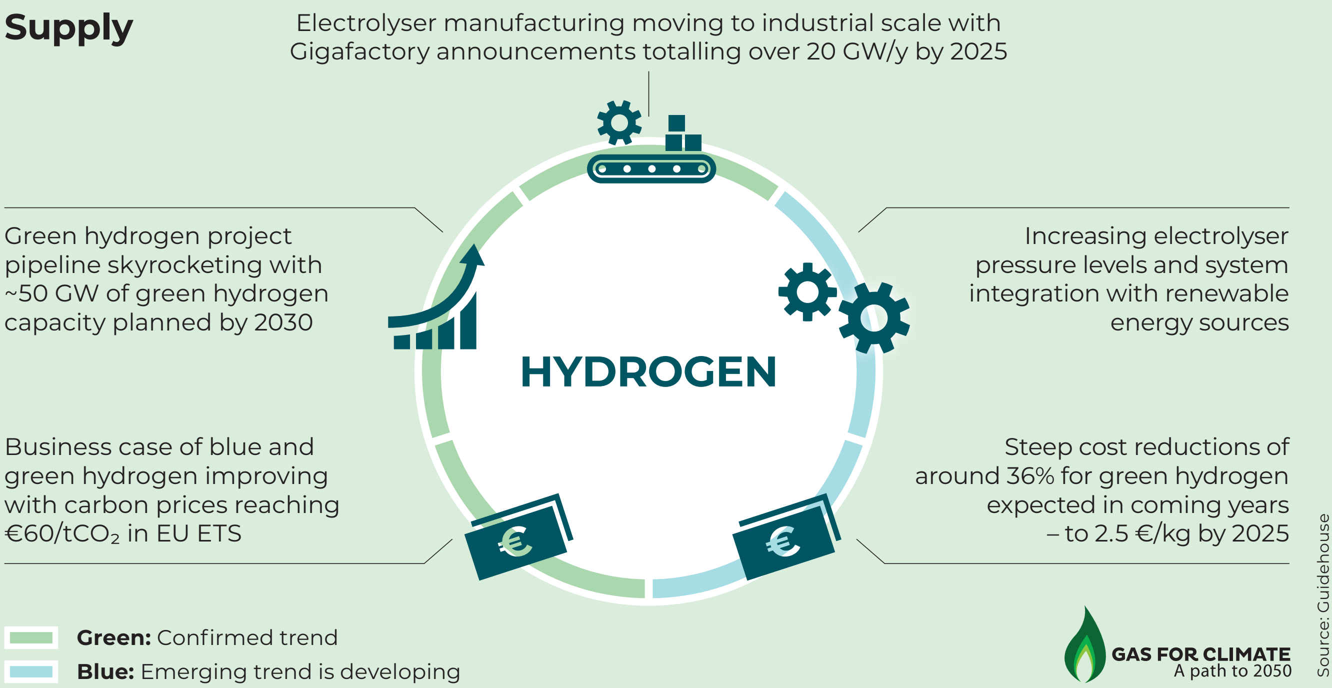
3. Hydrogen trends

Key takeaways

- Around 50 GW of **renewable hydrogen production capacity** has been announced to be deployed in the EU by 2030, 25% more than the EU's 40 GW installed capacity target. To keep up with the growing number of projects, **electrolyser gigafactories totalling over 20 GW/year of capacity by 2025** have been announced, with 88% of capacity in Europe.
- **Electrolyser technology developments** indicate a trend towards pressurised hydrogen production and increased levels of integration with renewable energy sources. These developments, next to increased deployment, could lead to a **green hydrogen levelised cost reduction of around 36% by 2025 to below 2.5 €/kg**.
- **While the business case for blue hydrogen improves with carbon prices hitting €60/tCO_2** in the EU ETS, the recent rise in natural gas prices renders blue and grey hydrogen uncompetitive (> €4/kg H_2) with alternatives such as green hydrogen. However, gas prices are expected to return to normal levels, while the carbon price in the EU ETS is expected to further increase.
- **Hydrogen transport and storage projects** are moving forward with several Important Projects of Common European Interest (IPCEIs). **Underground hydrogen storage** trials are ongoing in all geologies and are expected to reach competitive cost levels on a seasonal timeframe. **Developments in large-scale hydrogen compression** in the coming years will further enable the rollout of large-scale hydrogen transport and storage.
- Developments on industrial demand for green hydrogen side have been kickstarted by the EC in the Fit-for-55 package, by proposing a mandate of **50% green hydrogen share in industry by 2030**. In the steel sector, many steelmakers have announced a switch to hydrogen-based steelmaking. Announced plans alone add up to **35% of current primary steel capacity in the EU by 2030**, which would lead to around **80 TWh/year of hydrogen demand by 2030**, signalling a key trend.
- **Hydrogen-based e-fuels** will likely see a surge in adoption in Europe due to an EU mandate; this could lead to **around 90 TWh/year of hydrogen demand for e-fuels by 2030**. The proposal of a global carbon price has accelerated the discussion on future decarbonised fuels for shipping, initiating **a trend towards hydrogen-based fuels** such as e-ammonia and e-methanol. In aviation, **growing adoption of sustainable aviation fuel** due to government quotas and industry pledges will increase hydrogen demand.

3.1 Supply

The following sections detail key trends in the hydrogen supply market, touching on green hydrogen projects and developments in electrolyser manufacturing and technology and will detail the key trends in the blue hydrogen market. Further building on the trends as presented in the 2020 market state and trends report.



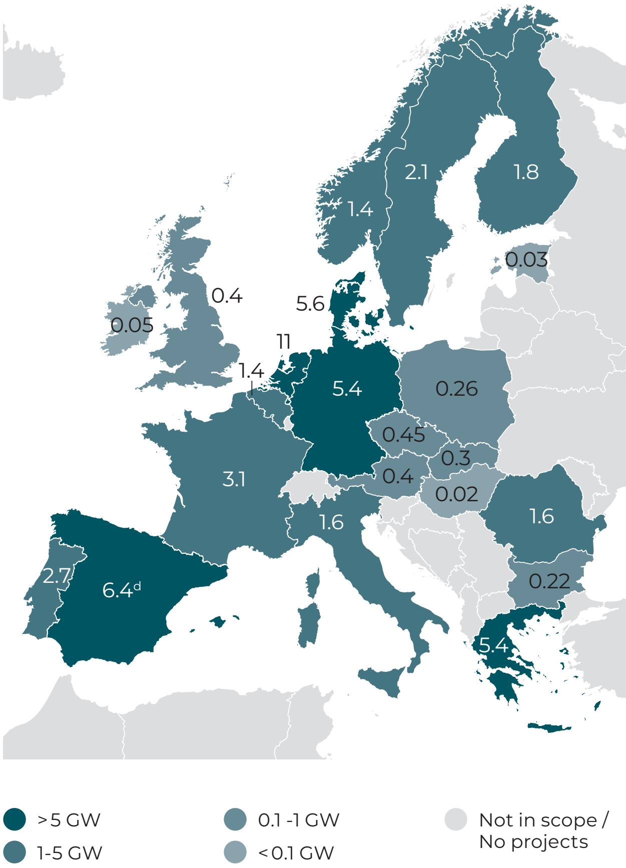
3.1.1 Green hydrogen project pipeline skyrocketing

The total announced electrolyser capacity continues to grow rapidly in Europe and beyond. In the EU, almost 50 GW[53] of renewable hydrogen projects have been announced to be in operation by 2030; this is approximately 25% more than the EU's 40 GW installed production capacity target by 2030.[54] Figure 13 sums up the announced electrolyser capacities based on project announcements per country. In Belgium, Spain, and the Netherlands, the announced projects exceed the targets in their respective national hydrogen strategies, as presented in Figure 21.

Europe leads the market in terms of announced projects, but projects outside of Europe are larger in size, often reaching the gigawatt and multi-gigawatt scale. Examples include the 1 GW NEOM project in Saudi Arabia (scheduled to be onstream by 2025)[55] and the approximately 16 GW Asian Renewables Hub project in Pilbara, Australia (scheduled to start exporting hydrogen by 2027/2028).[56]

53 Excluding the HyDeal project, which aims for 67 GW of installed electrolyser capacity in Spain by 2030 (McPhy, "HyDeal Ambition: Europe's first open and integrated green hydrogen consortium," 11 February 2021, https://mcphy.com/en/news/hydeal-ambition/).
54 European Commission, *A hydrogen strategy for a climate-neutral Europe*, 8 July 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.
55 Air Products, "Air Products, ACWA Power and NEOM Sign Agreement for $5 Billion Production Facility in NEOM Powered by Renewable Energy for Production and Export of Green Hydrogen to Global Markets," 7 July 2020, https://www.airproducts.com/news-center/2020/07/0707-air-products-agreement-for-green-ammonia-production-facility-for-export-to-hydrogen-market.
56 Asian Renewable Energy Hub, accessed 27 October 2021, https://asianrehub.com/.

Figure 13
Announced electrolyser capacity in GW by 2030



Guidehouse analysis based on EES, Hydrogen Europe and other project announcements as of October 2021.[c]

c Several projects may not be announced because of commercial or secrecy reasons, or just because they are at an early stage of development.
d Excluding the HyDeal project which would add 67 GW in Spain.

3.1.2 Electrolyser manufacturing moving to industrial scale

To keep up with the growing number of green hydrogen projects, large electrolyser manufacturing plants, electrolyser gigafactories, are being developed. As shown in Figure 14, around **88% of the electrolyser gigafactories announced will be located in Europe,[57] totalling 18 GW/year of capacity by 2025 in Europe**.

Gigafactories were announced by 12 major electrolyser suppliers,[58] and 4 GW/year of the announced 18 GW/year manufacturing capacity has been confirmed to be under construction in 2021. Further expansion of the capacity to meet increases in electrolyser demand accompany some announcements. Figure 14 summarises the announcements per country and technology.

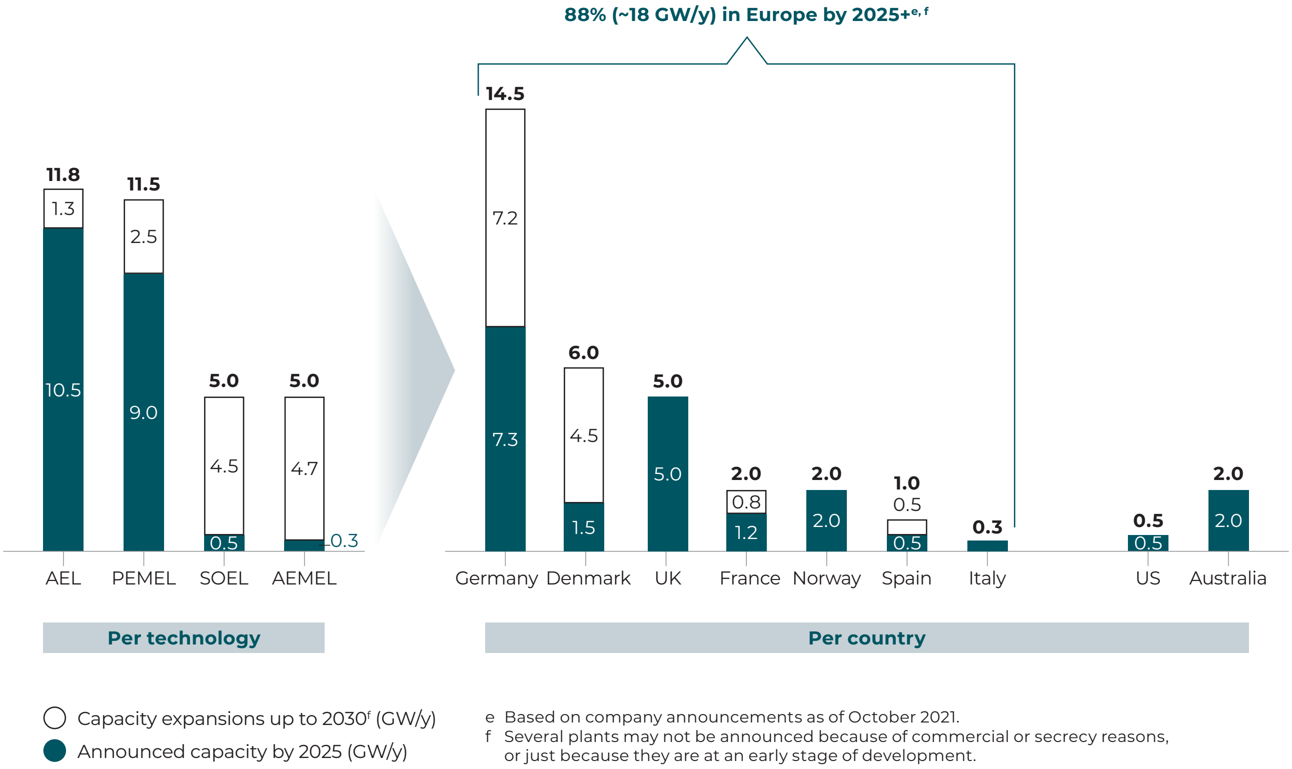
The announcements in Figure 14 cover the four main electrolyser technologies. The two most advanced electrolyser technologies are **alkaline (AEL) and proton exchange membrane (PEMEL)**. For AEL, conventional atmospheric alkaline can be further distinguished from updated, flexible, pressurised Alkaline systems,[59] as shown in Table 1. The upcoming technologies of **solid oxide (SOEL)** and **anion exchange membrane (AEMEL)** are expected to reach industrial scale in 2-3 years. It should be noted that there can be differences per supplier within the same technology.

Although electrolyser demand within the EU (based on the 40 GW target or the 50 GW of announced projects) is achievable with the announced approximately 18 GW/year of European production capacity, excess demand of electrolysers could be expected due to the following:

- 88% of globally announced manufacturing plants are located in Europe. These plants would largely also have to serve the global demand for electrolysers.
- More announcements are likely to come for projects deployed before 2030, although more or an expansion of electrolyser factories is also expected with the increasing demand for electrolysers.

57 In terms of production capacity in GW/year.
58 Includes Cummins (PEMEL, ES), Enapter (AEMEL, DE), Green Hydrogen Systems (AEL, DK), Haldor Topsoe (SOEL, DK), John Cockerill (AEL, FR), McPhy (AEL, FR/IT), Nel (AEL, Norway), Plug Power (PEMEL, US/AU), Siemens (PEMEL, DE), Sunfire (AEL, DE), ITM (PEMEL, UK), and ThyssenKrupp (AEL, DE).
59 Flexibility in terms of the ability to produce hydrogen flexibly with the variable power input of the renewable energy source. This depends on how fast the electrolyser can ramp up or down and start up or shut down.

Figure 14
Announced electrolyser manufacturing capacity in GW/year by 2025 and 2030[58]



e Based on company announcements as of October 2021.
f Several plants may not be announced because of commercial or secrecy reasons, or just because they are at an early stage of development.

3.1.3 Different electrolyser technologies and their KPIs

As described previously, there are four main different electrolyser technologies, which differ in their performance per identified key performance indicators (KPIs). The **appropriate electrolyser technology depends on the specific use case, as each technology performs best in different use cases**. Comparing the technologies is not straightforward; therefore, the different potential use cases are categorised as follows.

Projects can differ according to 1) the end-use application, 2) whether it is on-site, small scale and decentralised or large scale centralised production and, most importantly, 3) how the electrolyser would be connected or integrated with the renewable energy source. The latter is expected to have the largest impact on the technology choice. Therefore, this study categorises renewable hydrogen production plant integration levels according to the following **four cases** based on project announcements and interviews. The integration level ranges from no integration (Case 1) to full integration (Case 4). Green hydrogen projects using a combination of the different cases to increase full load hours[60], have also been announced.

60 Full load hours (FLHs) are calculated as the average annual hydrogen production divided by its rated capacity; they depend on the renewable energy source's power production: solar PV: ~1,800-3,500 FLHs; (Offshore) wind: 2,000-4,500 FLHs; hybrid solar and wind: 6,000-8,000 FLHs). When oversizing the power source in terms of design capacity, compared to the electrolyser, or adding batteries (especially to solar PV), higher levels of FLHs could be achieved. This would come at higher investment costs.

No integration → **Fully integrated**

1.
Grid-connected (constant): Electrolyser connected to the grid with high (>90%) load factor at constant power levels.

2.
Grid-connected (flexible): Electrolyser connected to the grid (with a Power Purchase Agreement (PPA)) with (offshore) wind park, solar farm, or both, but only running when contracted renewable energy source is producing energy.

3.
Island mode (flexible): Electrolyser directly connected onsite/off-grid to a (offshore) wind park, solar farm, or both.

4.
In the turbine (flexible): Electrolyser fully integrated in the (offshore) wind turbine.

The market is expected to move to more integrated renewable hydrogen production, where electrolysers complement the electricity grid and provide a solution to renewable energy projects unable to get an electricity grid connection. Table 1 illustrates the differences between the technologies with different KPIs. It also indicates the suitability of the electrolyser technologies for the potential cases mentioned before.

Table 1
Electrolyser KPIs
Assumes a large-scale (100-1,000 MW) plant to be deployed after 2025, such as one of the hydrogen IPCEIs. Estimates are averages based on electrolyser OEM interviews, company brochures, Hydrogen Europe (2020), and International Renewable Energy Agency (IRENA) (2020)

GW Scale ↑↓ kW Scale

Technology	Flexibility of operations[61]	Delivery pressure[62]	Years to industrial-scale production	Use of critical raw materials[63]	Land use/ footprint of full system	Average system efficiency (LHV_{el})[64]	Investment costs[65]	Service and maintenance costs[66]	Ability to use waste heat/water[67]	Suitability for cases mentioned above
Alkaline (AEL)	Medium	1-7 bar	0	Low (mainly nickel)	100-200 m²/MW (based on a GW system)	57%-60%	€200-€300/kW (GW scale)	~€10-€20/kW/y (>100,000 hrs stack economic lifetime)	Highly suitable (70-90 °C wastewater)	**Best suited for Cases 1 and 2 at GW scale.** Due to its low CAPEX and OPEX, especially when land availability is not an issue. Increased flexibility would also make AEL suited for Case 3, which could be added on the power side by introducing hybrid setups (solar PV plus wind or adding batteries).
Updated AEL	High	30-80 bar	1-2	Low (mainly, nickel)	20-60 m²/MW (based on GW system)	57%-60%	€400-€600/kW (GW scale)	~€15-€25/kW/y (>100,000 hrs stack economic lifetime)	Highly suitable (70-90 °C wastewater)	**Best suited for Case 3 and, to a lesser extent, Cases 1 and 2.** Increased flexibility to respond to the power source over standard AEL. Especially in cases where land is scarce or expensive and hydrogen at higher pressure levels (>30 bar) is needed, such as in hydrogen storage, transport, and use in fuel cells.
Proton Exchange Membrane (PEMEL)	High	1-70 bar	1-2	High (iridium, titanium, and platinum)	20-60 m²/MW (based on 100 MW system)	53%-54%	€500-€700/kW (GW scale)	~€20-€45/kW/y (40,000-80,000 hrs stack lifetime[68])	Suitable, but extra heat pump needed (50-80 °C wastewater)	**Best suited for Case 4** at current market state. Highly flexible and small foot-print/land use. For the other cases in current market state, uncompetitive on costs and efficiency, but technological improvements could increase stack lifetime and decrease stack degradation, decrease use of critical raw materials, and increase efficiency.
Solid Oxide (SOEL)	Medium	1-2 bar	4-5	Very low	110 m²/MW (based on ~3 MW system)	80%-82%[69]	€1,000-€1,250/kW (1 MW scale)	€70-€100/kW/y (~20,000-40,000 hrs stack lifetime)	N/A (SOEL uses steam as input)	**Best suited for Case 1** and where steam is available.[70] SOEL's high efficiency is optimally utilised in Case 1, with more load hours and more (expensive) electricity from the grid. Higher investment costs could be compensated because it is distributed over more kilograms of hydrogen. Technological improvements, mainly in stack lifetime, and industrialisation of manufacturing process, are needed to ensure economic competitiveness.
Anion Exchange Membrane (AEMEL)	High	35 bar	2	Low (mainly nickel)	28 m²/MW (based on 1 MW system fitting in 40 ft. container)	57%-60%	€500-€700/kW (1 MW scale)	~€30-€45/kW/y (~30,000-40,000 hrs stack economic lifetime)	Suitable but extra heat pump needed (50-60 degree wastewater)	**Potentially suited for all cases**, but currently only used at kW scale in dislocated decentralised systems. Seen as a PEMEL 2.0 because it has the same flexibility without needing critical raw materials. Economic competitiveness subject to technological improvements to increase stack lifetime and decrease investment costs.

61 Flexibility of operation at the stack level depends on multiple factors such as the to ability/speed of the system to respond to fluctuations in electricity load and cold and hot start-up times. Flexibility could also be added by designing a more modular system with multiple stacks (for instance, 10 2 MW stacks vs. four 5 MW stacks); the minimal load could even reach 4%-5% instead of the 10%-15% minimal load of a single stack system. The balance of plant (BoP) of the electrolyser decreases flexibility because it requires a minimum electrical load.
62 Mechanical compression could also be added separately at a later stage; compression is further discussed in the following sections.
63 Search for new materials and stack recycling are proposed to solve this issue.
64 Input of alternating current (AC) (grid) electricity (including rectifier and, mainly for PEMEL, water purification efficiency losses). Average efficiency included assumes efficiency degradation at stack level from beginning of life to end of life/stack replacement linearly.
65 Including BoP but excluding other costs such as for Engineering, Procurement and Construction (EPC), which could add up to €2,000/kW for a first-of-a-kind plant but are very case-specific and for later standardized plants reduced to neglectable amounts (Nouryon, 2020).
66 Based on operations and maintenance costs of 2% of yearly investment costs plus stack replacements costs based on a 30-year lifetime. Every 10 years for AEL/PAEL (one time) and every 5 years for PEMEL with decreasing costs based on IRENA's share of stack in total costs. In reality, the frequency of stack replacements can be optimized per use case, dependent on FLHs, efficiency (degradation), and electricity costs. PEMEL efficiency degrades approximately 2 times faster than AEL (~0.1% vs 0.2% /1,000 hrs.). Water impurities could further increase degradation for PEMELs.
67 Electrolyser wastewater could be used in district heating systems as a source of renewable heat, which requires water at around 90°C The electrolyser would have to be situated close to a district heating network or municipality, which will often not be the case. For instance, this was proposed by the Port of Rotterdam (Port of Rotterdam, "Hydrogen plants to provide new source of renewable heat for South Holland," 12 February 2021, https://www.portofrotterdam.com/en/news-and-press-releases/hydrogen-plants-provide-new-source-renewable-heat-south-holland).
68 PEMEL stacks degrade cell by cell and actually die, whereas AEL stacks degrade until hitting the nickel coating, which does not wear out. PEMEL stacks have an actual lifetime, whereas AEL/PAEL stacks have an economic lifetime as stack replacement is performed more so for economic reasons (to increase efficiency).
69 Assuming steam is available (100-150 °C), this could come from for instance the steelmaking process of the Fischer Tropsch process, which is used in e-fuel production.
70 Cases such as industrial processes where steam is available (steel), and using co-electrolysis (water plus CO_2) to produce renewable syngas (CO plusH_2), which is a feed gas for e-fuels production.

3.1.4 Increasing electrolyser operating pressures

Technological developments in eletrolysers are illustrated by the updated AEL technology and innovative SOEL and AEMEL technologies. **Electrolyser manufacturers are also looking to increase the system operating pressures**. This development is important because **hydrogen compression is energy-intensive**. It results from hydrogen having a relatively low volumetric energy density—almost 3 times less than methane—making mechanically compressing hydrogen an energy-intensive process.

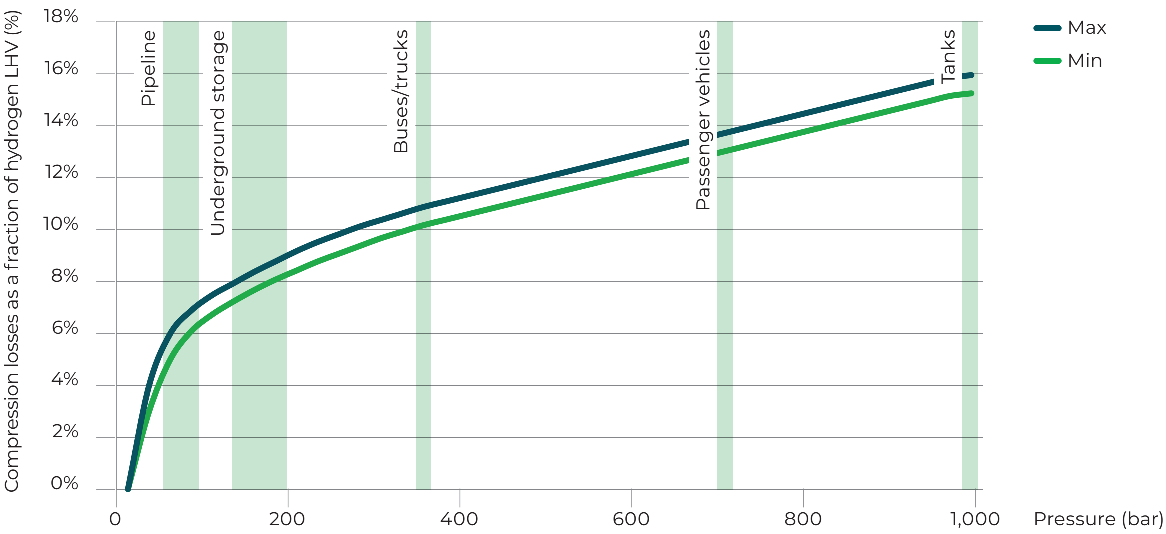
Most PEMEL and AEMEL electrolysers produce at around30 bar pressure whereas John Cockerill and Sunfire (formerly IHT) have produced up to 100 MW pressurised AELs for decades. Newer players in the market such as Green Hydrogen Systems and McPhy have specifically chosen to develop optimised systems at pressure. Recently, Nel, which sells atmospheric pressure AELs, has received a grant to develop a pressurised version of its electrolyser.[71]

The operating pressure of the **pressurised systems at current market state is around 30-40 bars**, which is the part of mechanical compression that requires the most energy (in terms of energy, ~6% of hydrogen at lower heating value), as Figure 15 shows. To get the hydrogen from 30 to the 70 bars needed for pipeline transport would only require less than 1% of the energy content of hydrogen at a lower heating value (LHV). Higher pressure levels are needed for pipeline transport (50-80 bar), underground storage (100-200 bar), and fuel cell vehicles/pressurised storage of hydrogen (>300 bar).

Increasing the electrolyser operating pressure has both advantages and disadvantages.[72]

+ **Efficiency losses in the process are minimal** due to the reduction of the *shadow effect*[73] but could result from gas permeation losses, which means more gas could end up on the oxygen side rather than the hydrogen side.
+ **Investment costs are potentially lower for the BoP**[74] because a separate mechanical compressor is not needed.

Figure 15
Efficiency losses of mechanical hydrogen compression (in % LHV) at different pressure levels (IRENA)[72]



71 Burgess, M., "Nel awarded grant to develop alkaline electrolyser platform," H2 View, 2 July 2020, https://www.h2-view.com/story/nel-awarded-grant-to-develop-alkaline-electrolyser-platform/.
72 IRENA, *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal*, December 2020.
73 Godula-Jopek, A. and D. Stolten, *Hydrogen Production: by Electrolysis*, 2015.
74 The Balance of Plant (BoP) means all the supporting components and auxiliary systems next to the electrolyser.

- + **The system physical footprint is smaller** for compressed systems, resulting from compressed hydrogen having a higher volumetric density; this means that at higher pressure levels a kilogram of hydrogen would take up less space/ square metres.[75]
- + **Increased flexibility** to produce hydrogen variably with renewable energy is another advantage enabled by the pressure differential. Additionally, there is also no need for a separate mechanical compression with its own ramp-up/ ramp-down times which can decrease flexibility.
- − **Higher quality (i.e., more costly) materials may be needed** to withstand the higher pressures.
- − **At increasing scale, the advantages in efficiency and costs decrease**. As with increasing size, mechanical compression stations get more efficient and relatively cheaper. Developments in compression technology such as electrochemical compressors could further improve the efficiency of separate compression.

Hence, the optimal operating pressure differs per case and will, among others, be dependent on:

- → **Project size**: Larger (gigawatt) centralised projects will most likely favour separate compression afterwards, smaller decentralised projects will most likely benefit from increasing electrolyser operating pressures
- → **Off-take pressure required**: Projects connected to transport/storage infrastructure need higher pressures of 50-150 bars, meaning separate compression is likely to be needed anyhow. While for projects connected directly to the end user pressure levels of <40 bars are sufficient, meaning the electrolyser output pressure could be sufficient.

3.1.5 Increasing level of system integration of electrolyser with renewable energy source

Next to higher operating pressures, this report also identifies **an increasing level of electrolyser system integration with the renewable energy source**. Producing renewable hydrogen in an (electricity) off-grid island mode can have several advantages:

- → **Reduce grid congestion** simply by not using the electricity grid. Grid-connected electrolysers could also provide grid balancing services when operating only when the electricity system does not need it and prevent electricity curtailment.[76]
- → **Help materialise solar and wind projects** for project developers unable to get a grid connection.
- → **Provide total system costs and efficiency advantages**, especially with full integration into a wind turbine, by removing the need for AC rectification, among others.[77]
- → **Absorb the variability in renewables production**. When hydrogen infrastructure and storage is in place, it could also provide a cheap way to transport and store energy in the longer term.[78]

The increasing level of system integration is confirmed by several announcements. The level of system integration ranges from next to the wind turbine[79] to on the foot of a floating offshore wind platform[80] to inside the (offshore) wind turbine.[81, 82] An example is the Aquaventus project (further discussed in Chapter 4), which aims to have 10 GW of offshore hydrogen production installed by 2030. French green hydrogen project developer Lhyfe also plans to integrate an electrolyser with floating offshore wind by 2022.[83]

75 For instance, hydrogen at around 30 bar takes up approximately three times less m² than hydrogen at atmospheric pressure.
76 Curtailment is the deliberate reduction of output of the power source to the grid, e.g. due to economic (low or even negative prices on the market) or technical (overloaded electricity grids) factors.
77 A wind turbine produces direct current (DC) electricity, which normally would be converted using a rectifier, to AC, which the electricity grid needs. The rectification leads to energy losses and adds costs. However, electrolysers need DC electricity, so the AC rectification step can be omitted when putting the electrolyser within the wind turbine. FuelCellsWorks, “ITM Power and Ørsted Unveil Wind Turbine Electrolyser for Bulk Hydrogen Production,” 10 April 2020, https://fuelcellsworks.com/news/itm-power-and-orsted-unveil-wind-turbine-electrolyser-for-bulk-hydrogen-production/.
78 Guidehouse, *Analysing future demand, supply, and transport of hydrogen*, European Hydrogen Backbone in cooperation with Gas for Climate, June 2021. https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf.
79 Kazilbash, S., “Siemens Gamesa Kicks Off Wind-to-Hydrogen Project in Denmark,” 22 September 2020, https://www.engineering.com/story/siemens-gamesa-kicks-off-wind-to-hydrogen-project-in-denmark.
80 ERM Dolphyn, Green hydrogen production at scale from floating offshore wind: https://ermdolphyn.erm.com/.
81 Siemens Energy and Siemens Gamesa (see: Federal Ministry for Economic Affairs and Energy, “How partners in the H2Mare lead project want to produce hydrogen directly on the high seas” at https://www.wasserstoff-leitprojekte.de/leitprojekte/h2mare)
82 ITM Power, Ørsted, Siemens Gamesa (ITM Power, “€5m EU Award to Study Offshore Green Hydrogen Production with Ørsted and Siemens Gamesa,” 8 January 2021, https://www.itm-power.com/news/5m-eu-award-to-study-offshore-green-hydrogen-production-with-orsted-and-siemens-gamesa).
83 Lhyfe (2021). *Offshore Green hydrogen production: the partnership between Lhyfe and Centrale Nantes on track for a world first*. (https://www.lhyfe.com/press/offshore-green-hydrogen-partnership-lhyfe-centrale-nantes-world-first/)

For **offshore wind electrolysis, the electrolyser pressure will likely be increased to 70-80 bar by 2025-2030**,[84] which would be enough for the hydrogen to reach the shore without needing costly offshore compression stations. This development combines both the system integration and pressure trends discussed in this chapter.

For **solar energy**, integration of hydrogen production emerges around concentrated solar power (CSP) with high temperature electrolysis such as the SOEL technology mentioned previously.[85] By using heat from CSP, this technology increases efficiency nearly 30% compared to the regular solar PV and AEL or PEMEL system (Table 1). Heliogen intends to install the first integrated solution by 2021, with unknown capacity.[86] Another option is for solar PV panels to directly produce green hydrogen (photo electrocatalysis). This technology is trialled by Enagás and Repsol. The companies aim to start operation of the first photo electrocatalysis plant in 2024, producing around 100 kg H_2/day.[87]

3.1.6 Steep green hydrogen cost reduction expected in coming years

The key trends described previously all have the potential to reduce the levelised production costs of green hydrogen along different cost factors, as shown in Figure 16:

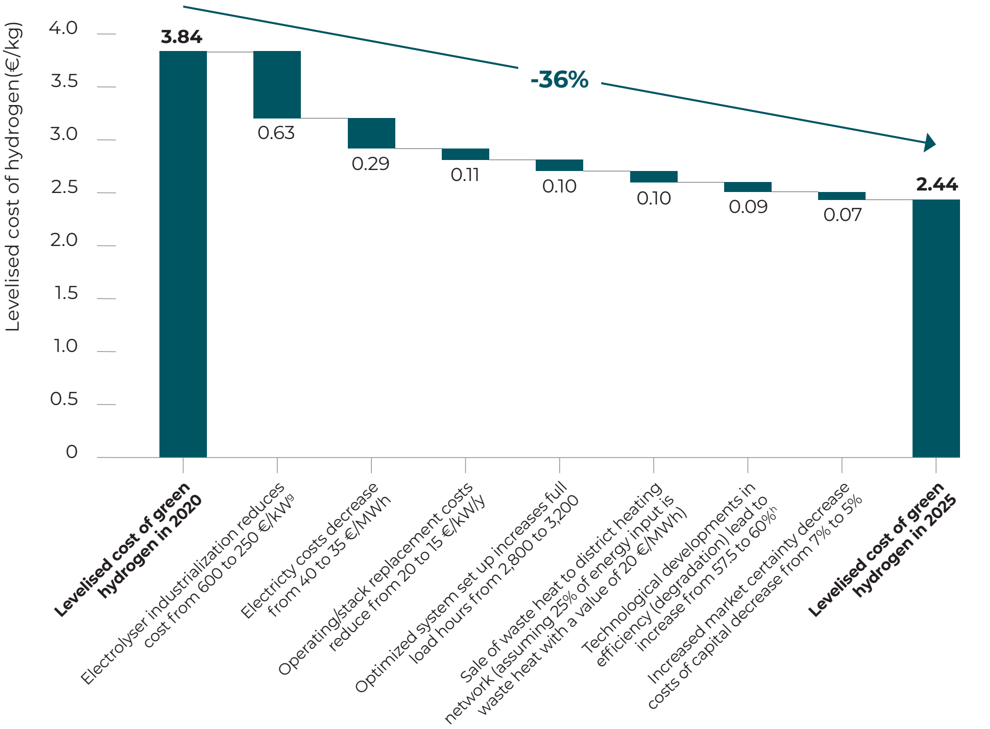
- **Electrolyser deployment in projects and electrolyser manufacturing at industrial scale**: Electrolysers show high learning rates of around 18%,[88] meaning every doubling of cumulative electrolyser production would lead to an 18% cost reduction. Coming from the approximately 1 GW/year production capacity to around 19 GW/year production capacity by 2025 would mean four doublings and, using the 18% learning rate, would lead to an around 45% electrolyser cost reduction. As already included in Table 1, this could reduce costs from €500-€600/kW to €200-€300/kW by 2025[89]. Operating and service contract costs would also be reduced as the stacks needed for stack replacements would be cheaper. Increased deployment is expected to lead to more certainty in the green hydrogen market and lower cost of capital.
- **Increasing level of system integration with renewable energy sources and increasing operating pressures** can lead to efficiency increases (e.g., removing rectification, need for additional mechanical compression) and optimal unitisation of a renewable energy source's energy production, leading to more load hours for the electrolyser and more production.

Figure 16 provides an illustrative example of the expected cost reduction for a large (>100 MW) green hydrogen project in north-western Europe connected to onshore wind. This example shows a reduction of around 36% in levelised costs of hydrogen to below 2.5€/kg. In renewable energy-abundant regions such as southern Europe, the costs could be even lower, with solar PV prices in 2021 already hitting levels of <€15/MWh.[90]

84 Several trials ongoing in the projects mentioned in the report and others such as GreenHyScale (https://cordis.europa.eu/project/id/101036935) or AquaVentus (https://www.aquaventus.org/presse/flagship-project-for-green-hydrogen/).
85 HELIOCSP (https://helioscsp.com/tag/hydrogen/) and Synhelion (https://www.solarpaces.org/synhelion-and-top-hydrogen-firm-advance-solar-hydrogen/).
86 Heliogen, "Bloom Energy and Heliogen Join Forces to Harness the Power of the Sun to Produce Low-Cost Green Hydrogen," 22 July 2021, https://heliogen.com/bloom-energy-and-heliogen-join-forces-to-harness-the-power-of-the-sun-to-produce-low-cost-green-hydrogen/.
87 Scully, J., "Naturgy, Enagás to develop green hydrogen plant in Spain alongside 400MW PV park," 21 December 2020, https://www.pv-tech.org/naturgy-enagas-to-develop-green-hydrogen-plant-in-spain-alongside-400mw-pv-park/.
88 IRENA, *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal*, December 2020.
89 Assumes pre-prepared site with AC power and tap water input and 99.9999% pure hydrogen output at 30 bars. Additional costs for Balance of Plant (BoP) and Engineering, procurement and construction (EPC) could significantly increase costs dependent on the project.
90 Rosell, A., "Spanish renewables auction secures lowest price of €0.01498/kWh," *pv magazine*, 27 January 2021, https://www.pv-magazine.com/2021/01/27/spanish-renewables-auction-secures-lowest-price-of-e0-01498-kwh/.

Figure 16

Illustrative example of green hydrogen levelised cost reduction up to 2025 (€/kg H_2)



g Electrolyser costs are based on pre-prepared site with AC power and tap water input. Additional EPC and BoP costs could significantly increase total investment costs.
h Average efficiency over lifetime, including efficiency degradation.

Guidehouse analysis, illustrative example of 100 MW+ green hydrogen project in north-western Europe using (offshore) wind energy. Assuming 30 years lifetime.

3.1.7 Blue hydrogen business case improves with rising carbon price

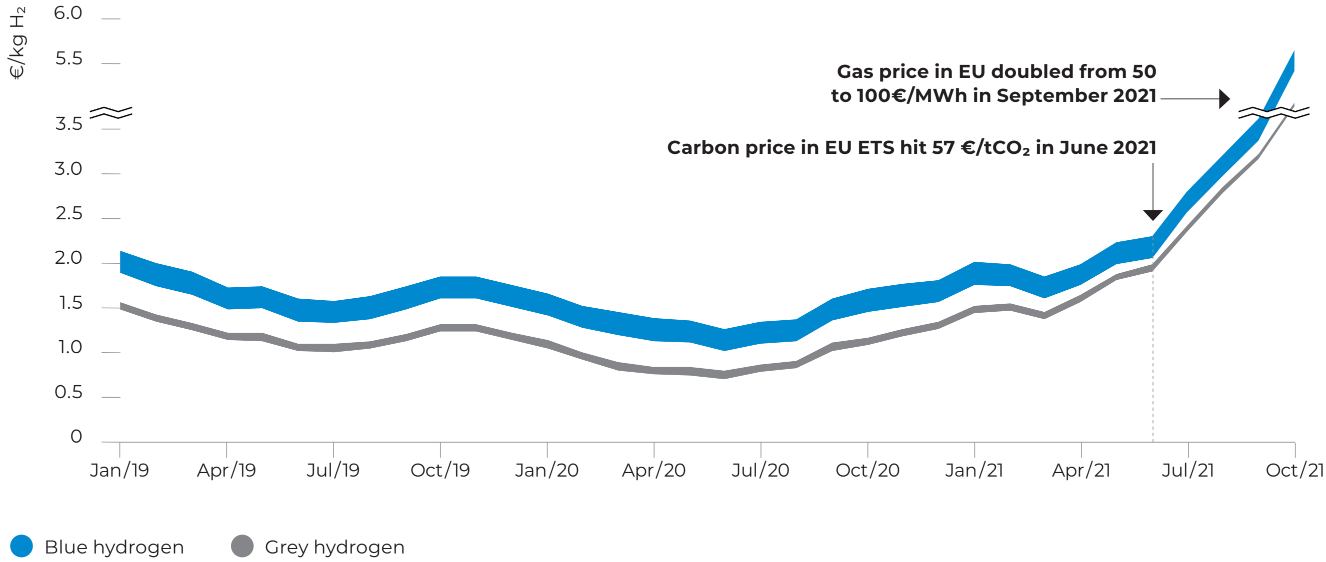
Besides renewable electricity-based green hydrogen, there is blue hydrogen, which is produced using natural gas and CCS. Next to the key trends for blue hydrogen already discussed in the 2020 market state and trends Report[91], four additional trends are identified in this report.

On a policy level, **funding on the EU level for blue hydrogen projects is not discussed** in the EC's recent Fit for 55 package. However, national-level funding for CCS is, for instance, present in the Netherlands (SDE++), where the cap for CCS funding was recently raised to include another 2.5 Mt CO_2-/year of capture and storage.[92]

The **rising CO_2 price improves the economics** of blue hydrogen significantly compared to grey hydrogen. The price of emission allowances under the EU ETS hit a record high of €60/ton CO_2, narrowing the average price gap between blue and grey hydrogen from €0.75 to €0.5/kg, as Figure 17 shows . However, the 10 fold increase in natural gas prices in 1 year (from €10 to €100/MWh) raises costs of both grey and blue hydrogen to uncompetitive levels of more than €4/kg. While gas prices are expected to return to normal levels,[93] the EU ETS carbon price is expected to increase further.[94]

91 2020 Market State and Trends report (https://gasforclimate2050.eu/publications/)
92 Solar Magazine, "3 billion euros extra budget for SDE++ subsidy," 21 September 2021, https://solarmagazine.nl/nieuws-zonne-energie/i25347/prinsjesdag-3-miljard-euro-extra-budget-voor-sde-subsidie
93 EU Agency for the Cooperation of Energy Regulators, *High Energy Prices*, October 2021, https://documents.acer.europa.eu/en/The_agency/Organisation/Documents/Energy%20Prices_Final.pdf.
94 Simon, F., "Analyst: EU carbon price on track to reach €90 by 2030," EURACTIV, 18 July 2021, https://www.euractiv.com/section/emissions-trading-scheme/interview/analyst-eu-carbon-price-on-track-to-reach-e90-by-2030/ and Twidale, S., "Analysts raise EU carbon price forecasts as gas rally drives up coal power," *Reuters*, 14 October 2021, https://www.reuters.com/business/energy/analysts-raise-eu-carbon-price-forecasts-gas-rally-drives-up-coal-power-2021-10-14/.

Figure 17
Cost spread between grey and blue hydrogen with natural gas and carbon prices over time in €/kgH_2



Guidehouse analysis: Gas price= Dutch TTF, carbon price = EU ETS, CAPEX grey = 600-800 €/kWinput, CAPEX blue = 1,100-1,500 €/kW$_{input}$, Efficiency grey = 75% (LHV), Efficiency blue = 69% (LHV), OPEX = 3%/yearly CAPEX, lifetime = 20 years, WACC = 6%, Availability = 95%, Capture rate blue 90-95%, Emission factor= 9kg CO_2/kgH_2, CO_2 transport and storage costs = 50-80 €/tCO_2

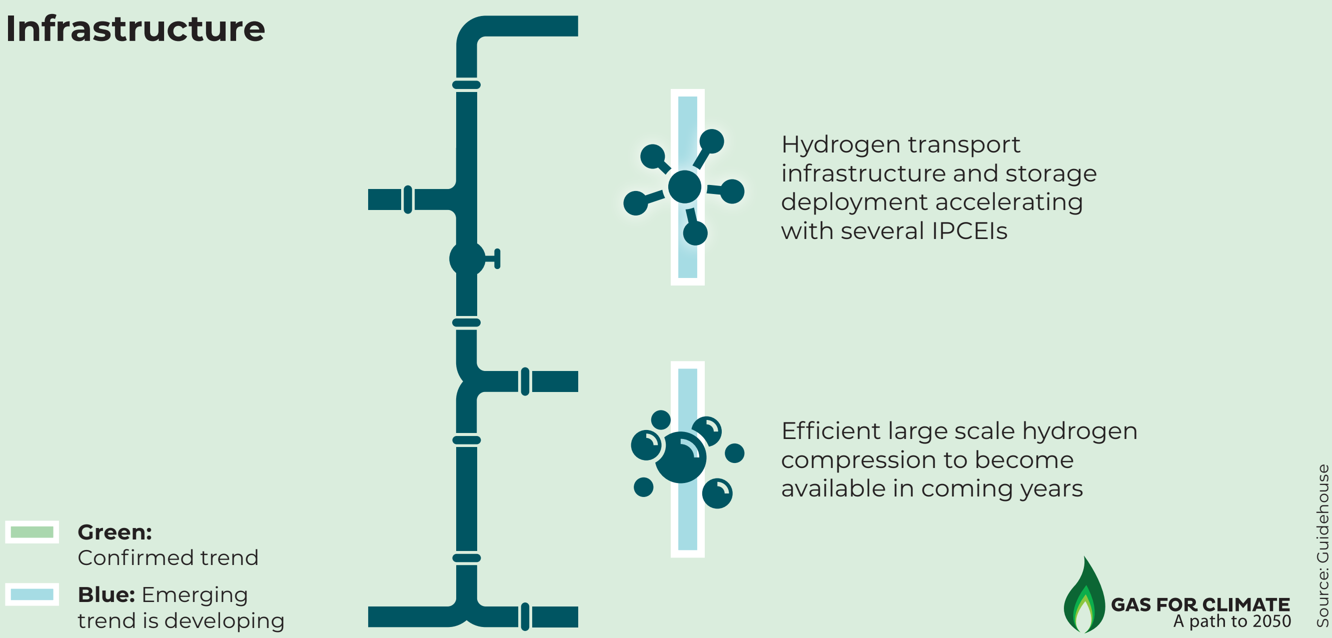
Blue hydrogen **projects continue to be developed**, and recent announcements are mostly located in potential large exporting regions such as Russia[95] and Saudi Arabia.[96] In the UK, blue or low-carbon hydrogen plays a large role in the hydrogen strategy,[97] and multiple announcements of large-scale projects have been made.[98]

Upstream methane emissions related to blue hydrogen production are increasingly under discussion. These discussions propose considering upstream emissions, mainly in the form of methane leakage, when calculating the total emissions of blue hydrogen.

3.2 Transport and storage

This section discusses the main trends in hydrogen transport and storage infrastructure, including the ongoing developments of projects in many countries across Europe and for underground hydrogen storage in all different geologies. Technological developments around hydrogen compression are also identified, which is key to the economic feasibility of large-scale hydrogen transport and storage.

95 Reuters, "Novatek says it reconfigures Obsky LNG project to produce hydrogen, ammonia," 23 June 2021, https://www.reuters.com/business/energy/novatek-says-it-reconfigures-obsky-lng-project-produce-hydrogen-ammonia-2021-06-23/.
96 Martin, M., "Saudi Aramco Bets on Blue Hydrogen Exports Ramping Up From 2030," *Bloomberg*, 27 June 2021, https://www.bloomberg.com/news/articles/2021-06-27/aramco-says-timing-of-next-blue-ammonia-cargo-depends-on-buyers.
97 Chestney, N., "UK government sets out strategy for a hydrogen economy," *Reuters*, 17 August 2021, https://www.reuters.com/world/uk/uk-government-launches-strategy-low-carbon-hydrogen-production-2021-08-16/.
98 For instance, the 1 GW project from BP; for more information, see: bp, "bp plans UK's largest hydrogen project," 18 March 2021, https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-plans-uks-largest-hydrogen-project.html.



3.2.1 Hydrogen transport infrastructure projects are moving forward

The European Hydrogen Backbone (EHB)[99] has set out a vision for an integrated pan-European backbone. **This vision is rapidly becoming a reality in several countries** with multiple (cross-border) infrastructure projects among the hydrogen IPCEIs;[100] for example:

- In the Netherlands, the Ministry of Economic Affairs and Climate Policy concluded that a national hydrogen network is necessary, largely by repurposing fossil gas pipelines, and asked Gasunie to lead the development.[101]
- In Germany, 13 hydrogen infrastructure projects were selected as hydrogen IPCEIs.[102] Examples include doing hydrogen (2026), LHyVE (2026), GETH2 (2024), and Green Octopus (2028).
- Between Germany and the Netherlands, the first steps for a cross-border hydrogen infrastructure are part of one of the 25 selected Dutch hydrogen IPCEIs, such as GETH2.[103]
- Denmark (Energinet) and Germany (Gasunie) recently conducted a pre-feasibility study for cross-border dedicated hydrogen infrastructure.
- In France, the Lacq Hydrogen (2026) and MosaHyc projects are under development.[104]
- In the rest of the EU, smaller national stretches are starting to develop, mostly around industry clusters, for instance in Belgium, Spain, and Italy.
- Developments in blending and deblending of hydrogen in the gas networks are ongoing in multiple European countries, including Germany,[105] France,[106] and Spain.[107] Some projects also include the use of membrane technology to separate the hydrogen from the fossil gas.[108]
- Additionally, market dialogues have been carried out in multiple countries, including the Netherlands, Germany and Denmark.

99 Guidehouse, *2021: Extending the European Hydrogen Backbone* prepared April 2021, https://gasforclimate2050.eu/wp-content/uploads/2021/06/European-Hydrogen-Backbone_April-2021_V3.pdf
100 IPCEIs are "large projects that address a market failure or other important systemic failures in a European context based on common European interests." See: European Commission, "IPCEIs on hydrogen," accessed 28 October 2021 https://ec.europa.eu/growth/industry/policy/supporting-clean-hydrogen/ipceis-hydrogen_en.
101 Government of the Netherlands, "State Secretary Yeşilgöz-Zegerius takes first step towards developing national hydrogen network," 30 June 2021, https://www.rijksoverheid.nl/actueel/nieuws/2021/06/30/staatssecretaris-yesilgoz-zegerius-zet-eerste-stap-voor-ontwikkeling-landelijk-waterstofnet.
102 "Randall, C., "IPCEI to fund 12 European hydrogen mobility projects," electrive.com, 3 June 2021, https://www.electrive.com/2021/06/03/ipcei-to-fund-12-european-hydrogen-mobility-projects/.
103 Government of the Netherlands, "Projects proposed by the Netherlands as direct partner for the first round of IPCEI hydrogen," 24 June 2021, https://www.rijksoverheid.nl/documenten/kamerstukken/2021/06/24/bijlage-2-projecten-die-door-nederland-zijn-aangedragen-als-directe-partner-voor-de-eerste-ronde-van-de-ipcei-waterstof.
104 Energinet, "Energinet and Gasunie publish pre-feasibility study on hydrogen infrastructure," 27 April 2021, https://en.energinet.dk/Gas/Gas-news/2021/04/27/GUD-rapport.
105 OGE, "First green hydrogen to be fed into gas transmission system in Northern Germany," 15 December 2020, https://oge.net/en/press-releases/2020/erste-einspeisung-von-gruenem-wasserstoff-in-das-bestehende-norddeutsche-gas-fernleitungsnetz and ONTRAS, "European research project on hydrogen separation: Pilot plant for testing membranes in the separation of natural gas and hydrogen," 13 May 2020, https://www.ontras.com/en/h2-membran.

3.2.2 Underground hydrogen storage being trialled along all possible geologies

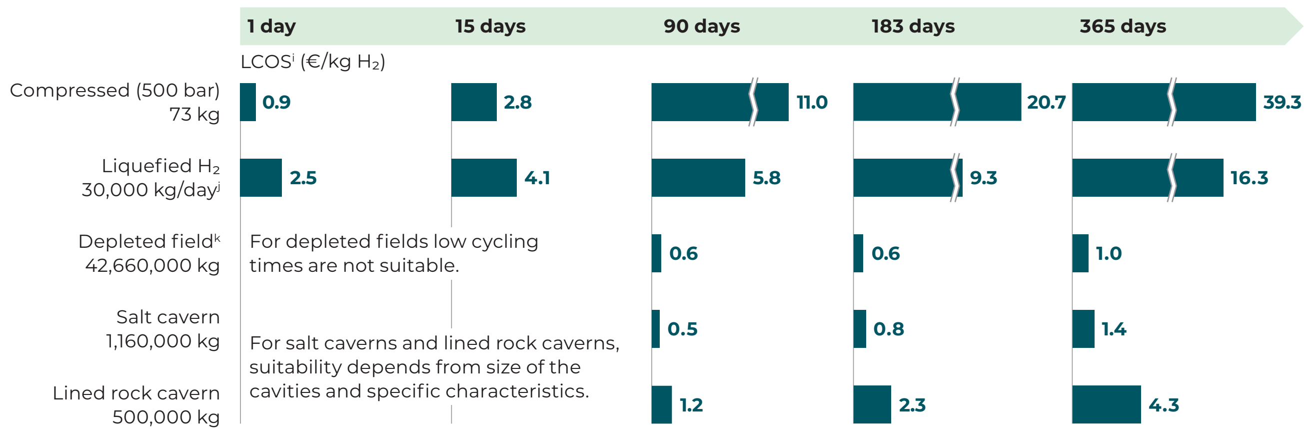
Next to hydrogen pipeline transport, recent studies from GIE,[109] Agora,[110] and EHB[111] have all concluded that storage has an essential role in an integrated European hydrogen system by absorbing the variability of green hydrogen and renewable energy production, among others.

Underground hydrogen storage is under development in all different possible geologies, and the **first hydrogen storage facilities are expected to become available in the coming years**.

- **Salt cavern storage**, already proven at a large scale in the UK and the US, is being trialled in many countries across Europe, such as the Netherlands (HyStock), Germany (Gronau-Epe/GETH2), Denmark (Green Hydrogen Hub), and France (HyGeo).
- **Aquifer storage** is being investigated in France in the Lacq Hydrogen project by Teréga (among others) and in Spain by Enagás.
- **Lined rock cavern storage** for hydrogen is being constructed in Sweden as part of the HYBRIT joint venture involving LKAB, SSAB, and Vattenfall[112] to reach full pilot scale in 2024.
- **Depleted gas fields** are being tested for hydrogen storage in Austria (RAG) and Spain (Enagás), although only in admixtures with methane.

Figure 18 shows the different options and associated costs of hydrogen storage. In general, compressed or liquefied hydrogen storages can be used as short-term storage options with smaller hydrogen volumes, while underground geological storages are suitable for large volumes for long-term seasonal storage needs. The figure shows, illustratively, that long-term (underground) seasonal storage (90-365 days) is economically feasible, while short-term (>1-15 days) storage options are more costly at present.

Figure 18
Estimation of levelised cost of storage (LCOS) in €/kg H_2 for different hydrogen storage options



i Excludes the cost of hydrogen production.
j Refers to liquefaction plant capacity.
k For depleted field, performances are conditioned by the specific characteristics of the field, that can determine significative differences in the performance indicated the performance given corresponds to the best-case scenario.

Guidehouse and Snam illustrative analysis.

106 Burgess, M., "Gas transmission system operators study hydrogen potential," H2 View, 16 January 2020, https://www.h2-view.com/story/gas-transmission-system-operators-study-hydrogen-potential/.
107 Ali, S., "Spain's Nortegas advances towards blending hydrogen in gas network," H2 Bulletin, 24 February 2021, https://www.h2bulletin.com/spains-nortegas-advances-towards-blending-hydrogen-in-gas-network/.
108 2020 Market state and Trends report (https://gasforclimate2050.eu/publications/)
109 GIE, *Picturing the value of underground gas storage to the European hydrogen system*, prepared by Guidehouse, June 2021, https://www.gie.eu/wp-content/uploads/filr/3517/Picturing%20the%20value%20of%20gas%20storage%20to%20the%20European%20hydrogen%20system_FINAL_140621.pdf.
110 Agora Energiewende and AFRY Management Consulting, *No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe*, February 2021, https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf.
111 Guidehouse, *Analysing future demand, supply, and transport of hydrogen*, European Hydrogen Backbone in cooperation with Gas for Climate, June 2021. https://gasforclimate2050.eu/wp-content/uploads/2021/06/EHB_Analysing-the-future-demand-supply-and-transport-of-hydrogen_June-2021.pdf.
112 Bellini, E., "Work begins on green hydrogen storage cavern in Sweden," *pv magazine*, 8 April 2021, https://www.pv-magazine.com/2021/04/08/work-begins-on-green-hydrogen-storage-cavern-in-sweden/.

3.2.3 Efficient large-scale hydrogen compressors to become available in coming years

As discussed in Chapter 3.1.4, hydrogen compression can be an energy-intensive process. Although electrolysers are moving to higher operating and output pressures, additional compression is needed to transport the hydrogen (60-80 bar) or store the hydrogen (150-200 bars). In the coming years, with the development of dedicated hydrogen infrastructure and large-scale storage, hydrogen compression is likely not needed assuming modest transport and storage capacity requirements. However, with increasing flows and need for storage, efficient hydrogen compression will become crucial for large-scale, long-distance hydrogen pipeline transport and underground storage.

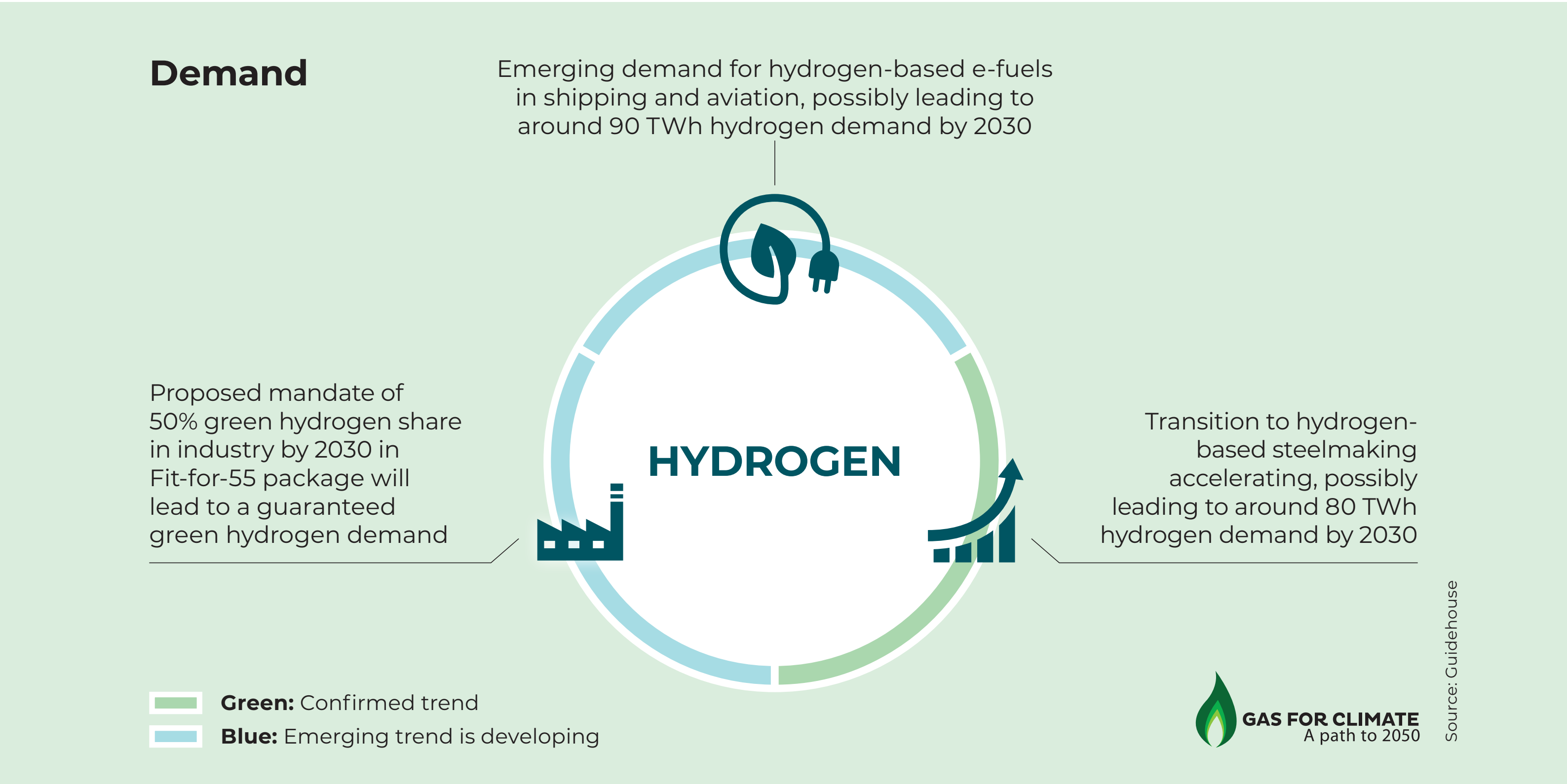
Two compressor technologies, reciprocating and centrifugal compressors, are being developed by the market with the aim of realizing larger capacities systems.

Advanced reciprocating compressors currently represent the most efficient option for compressing pure hydrogen.[113]

Largescale centrifugal compressors are being developed in parallel with the aim of achieving lower maintenance costs due to longer running times, while potentially also offering an efficiency advantage over reciprocal compression, as internal friction will not raise proportionally with increased capacity.[114] These **largescale centrifugal hydrogen compressors at 50 MW-100 MW scale are expected to become available with the deployment of hydrogen infrastructure**, according to suppliers. There is also increasing interest in electrochemical hydrogen compression using membranes from, among others, H2GAR[115] and HyET.[116] Electrochemical compression has several advantages such as energy efficiency and lower maintenance and investment costs, but it is only available on smaller scales (<2,000 kg/day or ~<3 MW[117]).

3.3 Demand

The following sections contain the key trends in the hydrogen demand market, starting with industrial hydrogen demand and specifically discussing the steel sector. The section then discusses hydrogen demand in transport and e-fuels production.



3.3.1 Industrial hydrogen demand kickstarted with new EU mandate

A mandate from the EC on renewable hydrogen in industry is expected to create guaranteed demand for green hydrogen. The proposed mandate in the Fit for 55 package[118] consists of a 50% renewable hydrogen target by 2030 for all hydrogen used in industry.[119] The mandate includes ammonia but excludes industrial hydrogen's largest end-use sector, refining, which is included in the transport sector.

3.3.2 Transition to hydrogen-based steelmaking accelerating

In the steel sector, the transition to hydrogen-based steelmaking is rapidly accelerating - around 41 Mt/year of hydrogen-based steelmaking capacity has been announced to be operational by 2030 as shown in Table 2. With around 40 Mt/year of direct reduction (DR) plant capacity around 45 Mt/year of steel could be produced, which makes up approximately 35% of current primary steel production capacity in Europe.[120] This could translate to around 80 TWh/year of hydrogen demand.[121]

This new hydrogen-based production process has two main steps that can be integrated in one plant or separated into in two different plants. The DRI-EAF process will reduce emissions by more than 95% compared to the current coal-based blast furnace/integrated steelmaking route:

1. **Direct reduction of iron ore (DRI)**: Hydrogen is used as a reducing agent for iron ore in the DR plant creating directly reduced iron, which can be turned into a solid intermediate tradeable product called hot briquetted iron (HBI). Several DR plants exist outside of Europe, running on natural gas instead of hydrogen.
2. **Electric arc furnace (EAF)**: The DRI/HBI is melted into crude steel. EAFs are widely used in secondary steelmaking in Europe, using mostly recycled steel (scrap) instead of DRI or HBI.

Table 2 summarises summarizes the announcements on hydrogen DR plants of steelmakers or iron ore miners in Europe.

113 Because of the technology's interdependency on the low molecular weight of hydrogen. Reciprocating compressors are therefore able to achieve high overall compression ratios with fewer stages compared to centrifugal compressors, thus reducing both the CAPEX and the size of the compressor.
114 However, due to the lower pressure rise per stage of the compressor, the development of centrifugal compressors depends on the ability to increase the impeller operating speed and solve material strength limits, to reduce the number of stages required and thus the rotordynamic complexity.
115 P. de la Flor, F., "H_2 Gas Assets Readiness (H2GAR)," presented at the 34th Madrid Forum, https://ec.europa.eu/info/sites/info/files/energy_climate_change_environment/events/presentations/05.03_mf34_presentation-h2gar-de_la_flor.pdf.
116 HyET Group, "Compression," accessed 25 October 2021, https://hyethydrogen.com/compression/.
117 The European Hydrogen Backbone would need compressor stations of 20 MW-100 MW when hydrogen flows are picking up after 2030.
118 European Commission, "Proposal for a Directive of the European Parliament and of the Council amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652," 14 July 2021, https://ec.europa.eu/info/sites/default/files/amendment-renewable-energy-directive-2030-climate-target-with-annexes_en.pdf.
119 GenH2, "Hydrogen Wins as 'Fit for 55' Pushes EU Decarbonization into High Gear," 30 July 2021, https://www.genh2.net/post/hydrogen-wins-as-fit-for-55-pushes-eu-decarbonization-into-high-gear#:~:text=The%20Fit%20for%2055%20package,hydrogen%20refilling%20stations%20by%202025.
120 Eurofer, "Where is steel made in Europe?" accessed 23 October 2021, https://www.eurofer.eu/about-steel/learn-about-steel/where-is-steel-made-in-europe/.
121 Natural gas could also be used when hydrogen is not yet available at sufficient scale, as proposed in some of the announcements.

Table 2
Overview of European steelmakers which announced hydrogen-based steel production as of October 2021

Location	Country	Company	Current steel capacity	Announced hydrogen Direct Reduction (DR) plants (Mt DRI/year) and timing[122]
Duisburg		thyssenkrupp	11.6 Mt/y	2030: 4-5 Mt/y of DR plants[123]
Taranto		ArcelorMittal	11.5 Mt/y	N/A: 6 Mt/y of DR plant(s) in planning stage
IJmuiden		TATA STEEL	7.2 Mt/y	2027-2030: ~2.5 Mt/y DR plant[124]
Dunkirk		ArcelorMittal	6.8 Mt/y	2030: ~2.3 Mt/y DR plant[125]
Linz		voestalpine	6 Mt/y	2021: 0.25 Mt/y DR plant (pilot)
Ghent		ArcelorMittal	5 Mt/y	2030: 2.5 Mt/y DR plant
Salzgitter		SALZGITTER AG	4.8 Mt/y	2022: pilot DR plant, 2030: ~2.5 Mt/y of DR plants[126]
Galati		LIBERTY STEEL	3.2 Mt/y	2030: 2.5 Mt/y DR plant
Bremen/Eisenhüttenstadt		ArcelorMittal	2.3 Mt/y / 2.8 Mt/y	2030: 3.15 Mt/y of DR plants[127]
Gijon/Sestao		ArcelorMittal	2 Mt/y	2025: 2.3 Mt/y DR plant plus existing EAFs
Hamburg		ArcelorMittal	1.1 Mt/y	2030: 0.7 Mt/y DR plant
Ascoval		saarstahl	0.6 Mt/y	2030: 2 Mt/y DR plant plus existing EAF
Norrbotten		LKAB	N/A	2030: 2.7 Mt/y DR - HBI plant
Norrbotten		H2 green steel	N/A	2030: 4.5 Mt/y DR plant[128]

122 1 ton of crude steel requires 0.9 tonne of HBI, which is produced in the DR plant per Holling et al. (2020) Bewertung der Herstellung von Eisenschwamm unter Verwendung von Wasserstoff. Capacities based on company announcements and Agora Energiewende and AFRY Management Consulting, *No-regret hydrogen: Charting early steps for H_2 infrastructure in Europe*, February 2021, https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf.

123 Based on 9 TWh/year H_2 demand for DRI by 2030; Carbon2Chem project will require another 9 TWh/year of H_2 (LHV) by 2030. From ThyssenKrupp Steel European Hydrogen Backbone presentation from June 2021.

124 Tata Steel has decided to go for the DRI route option (see Roland Berger, *Feasibility Study climate neutral paths* at https://www.fnv.nl/getmedia/a3b9784e-e363-4cc4-ac4d-aeb9c6b6a00c/210902-Tussenrapportagegroen-staal.pdf). Capacity is estimated using current capacity of Blast Furnace 6 (2.77 Mt/y steel capacity).

125 Based on 2.85 Mt/year emission reduction from 7.5 Mt/year emissions today (EUTL), meaning 38% of capacity, which is a 2.6 Mt/year steel or 2.3 Mt/year DR plant (see ArcelorMittal, "Air Liquide and ArcelorMittal join forces to accelerate the decarbonisation of steel production in the Dunkirk industrial basin" at https://corporate.arcelormittal.com/media/news-articles/air-liquide-and-arcelormittal-join-forces-to-accelerate-the-decarbonisation-of-steel-production-in-the-dunkirk-industrial-basin).

126 Based on 2.8 Mt/year DRI-EAF steel production (see GrInHy2.0, "Green Industrial Hydrogen for future green steelmaking" at https://www.fch.europa.eu/sites/default/files/FCH%20Docs/Simon%20Kroop%20-%20GrinHy2.0%20%28ID%2012386723%29.pdf).

127 Based on 3.5 Mt/year steel production, two DR plants: one in Bremen, one in Eisenhuttenstadt (see ArcelorMittal, "ArcelorMittal plans major investment in German sites, to accelerate CO_2 emissions reduction strategy and leverage the hydrogen grid" at https://corporate.arcelormittal.com/media/news-articles/arcelormittal-plans-major-investment-in-german-sites-to-accelerate-co2-emissions-reduction-strategy-and-leverage-the-hydrogen-grid).

128 Based on 5 Mt/year steel plant (see InnoEnergy, "H_2 Green Steel will produce 5M tons of CO_2-free steel, mobilize 2.5B€ investments and create 10,000 jobs" at https://www.innoenergy.com/news-events/h2-green-steel-will-produce-5m-tons-of-co2-free-steel-mobilize-25b-investments-and-create-10-000-jobs/).

3.3.3 Emerging demand for hydrogen-based e-fuels in shipping and aviation

Electrofuels (e-fuels), synthetic fuels (synfuels), or renewable fuels of non-biological origin (RFNBOs) are carbon-neutral gaseous or liquid fuels generated from renewable electricity. All are based on green hydrogen, which is driving hydrogen demand. Examples of e-fuels are e-methanol, e-ammonia, and e-kerosene.

In the Fit for 55 package, a 2.6% target was set for RFNBOs in transport, including a subtarget for RFNBOs in aviation of 0.7%.[129] This target could translate into around **90 TWh/year of hydrogen demand by 2030 in the EU**.

In shipping, e-fuel demand potentially faces a surging demand, as **a carbon levy at the global level is being considered** by the International Maritime Organisation at a price of €86/tCO_2 (\$100/tCO_2);[130] On EU level, the EC plans to include shipping in the ETS gradually from 2023 to 2026 under the Fit for 55 package.[131]

The possible carbon levy has **accelerated the discussion on future fuels in the shipping sector**.[132] Maersk (17% global market share) called for moving away from LNG as a future shipping fuel due to the methane slip in the engine[133] and to hydrogen-based fuels such as e-methanol and ammonia.[134] Maersk announced it is accelerating its fleet decarbonisation using e-methanol and ordered eight 16,000 TEU[135] ocean-going vessels that will run on e-methanol, partly sourced from the e-methanol IPCEI[136] from the Danish company Reintegrate.

In the aviation sector, a newly formed collation of over 50 companies, Clean Skies for Tomorrow, pledged to **replace 10% of global jet fuel with sustainable aviation fuel by 2030, which includes biokerosene and e-kerosene**.[137] In 2021, Germany introduced a 2% e-kerosene quota by 2030.[138] These developments would lead to a significant increase in hydrogen demand because e-fuels or e-kerosene would require significant amounts of hydrogen. The biokerosene route could also require hydrogen for upgrading, depending on the technology and feedstocks used. Examples of existing projects are found in Germany[139] and Norway.[140] Seeing the limited number of existing e-fuel projects, e-fuels are still in the early development stages, which will need to develop into a trend.

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131 Saul, J. and Abnett, K., "EU proposes adding shipping to its carbon trading market," *Reuters*, 14 July 2021, https://www.reuters.com/business/sustainable-business/eu-proposes-adding-shipping-its-carbon-trading-market-2021-07-14/#:~:text=Under%20the%20EU%20plan%2C%20shipping,possible%20bans%20from%20EU%20ports.
132 Adamopoulos, A., "Shipping leaders disagree on future of LNG in shipping," *Lloyd's List*, 12 May 2021, https://lloydslist.maritimeintelligence.informa.com/LL1136761/Shipping-leaders-disagree-on-future-of-LNG-in-shipping.
133 Pavlenko, N., et al., "The climate implications of using LNG as a marine fuel," ICCT working paper, 28 January 2020, https://theicct.org/publications/climate-impacts-LNG-marine-fuel-2020.
134 Gallucci, M., "Why the Shipping Industry Is Betting Big on Ammonia," *IEEE Spectrum*, 23 February 2021, https://spectrum.ieee.org/why-the-shipping-industry-is-betting-big-on-ammonia.
135 A TEU (20-foot equivalent unit) is a measure of volume in units of 20-foot containers. For example, large container ships are able to transport more than 18,000 TEU. One TEU is one 20-foot container.
136 Maersk, "Maersk secures green e-methanol for the world's first container vessel operating on carbon neutral fuel," 19 August 2021, https://www.maersk.com/news/articles/2021/08/18/maersk-secures-green-e-methanol.
137 Foreign Affairs News, "Clean Skies for Tomorrow: 10% SAF by 2030," 23 September 2021, https://foreignaffairsnews.com/clean-skies-for-tomorrow-10-saf-by-2030/.
138 airliners.de, "Government resolves two percent PTL quota for kerosene from 2030," 3 February 2021, https://www.airliners.de/regierung-beschliesst-zweiprozentige-ptl-quote-kerosin-2030/59219.
139 Young, C., "Germany Has Opened the World's First Clean Jet Fuel Plant," *Interesting Engineering*, 6 October 2021, https://interestingengineering.com/germany-has-opened-the-worlds-first-clean-jet-fuel-plant.
140 Norsk e-Fuel, "Supplying your renewable fuel. Unlimited." accessed 20 October 2021, https://www.norsk-e-fuel.com/en/.

4. Biomethane showcase projects and hydrogen IPCEIs

4.1 Biomethane

Biogas Wipptal

- Vipiteno, Italy
- Biogas Wipptal srl
- In operation, upgraded in 2021
- Dairy cow manure
- 2.5 $MW_{el\ equivalent}$ (11 tpd bioLNG)

The Biogas Wipptal project combines many advantages of biomethane production. In 2021, the existing biogas plant was upgraded to produce biomethane. The biogas is produced with AD. Dairy cow manure is used as feedstock. The digestate processed is used to make dry and liquid fertiliser.

The biogas is upgraded to biomethane and is liquified to be used as bio-LNG in the transport sector.

The separated biogenic CO_2 is not emitted into the atmosphere; it is liquified for use in the food and beverage industry and to produce dry ice.

Project Air

- Stenungsund, Sweden
- Perstorp
- Under development, operational in 2025
- 200 kt/year biomethanol

In Stenungsund, north of Gothenburg, Perstorp is developing a production site for sustainable methanol to replace 200 kton/year of fossil methanol in its chemical production site.

Biomethane delivered by the Danish gas supplier Nature Energy will be combined with onsite industrial residue streams to be converted to syngas. This syngas will be enriched with CO_2 captured from another onsite chemical process.

An electrolyser, operated by Fortum and Uniper, is going to deliver green hydrogen generated with green electricity and purified wastewater. This gas mix will then be used as feedstock for the methanol production. This project aims to reduce CO_2 emissions by 500 kton annually.

Korskro, Denmark

Nature Energy

In operation, upgraded 2020

Manure

490 GWh/year biomethane
16.25 kt/year biogenic CO_2

Korskro biogas plant (update)

The biogas plant in Korskro recently upgraded its production size and added a carbon capture unit. The total capacity of biomethane production increased from 22 million m³ (in 2019) to 49 million m³ biomethane.

The CO_2 separated in the biogas upgrading process is now captured and processed. After purification, the biogenic CO_2 is used in the food industry and beyond. Annually 16,250 tons of bio-CO_2 is captured and utilised, which is equal to 25% of the Danish CO_2 demand.

FirstBio2Shipping

The project FirstBio2Shipping just received financial support by the European Innovation Fund. The project consists of three units: biogas treatment, liquification and carbon capture.

The aim is to produce 6 million m³ of biogas, 2,400 tons of bio-LNG and 5,000 tons of biogenic CO_2 annually.

The bio-LNG is used in the maritime sector, replacing heavy fuel oil, and thereby reducing emissions from maritime shipping. The innovative aspect of this project is a new technology from Nordsol called iLNG, which aims to increase the bio-LNG quality while reducing methane leakage.

The Netherlands

ATTERO BV, Bio-LNG Hub Wilp B.V., Nordsol

Under development

36 GWh/y biogas, 2.4 kt/y bio-LNG, and 5 kt/year of Biogenic CO_2

BioLNG EuroNet

Shell, Scania, IVECO, DISA, and Nordsol

Rolled out, started in 2018

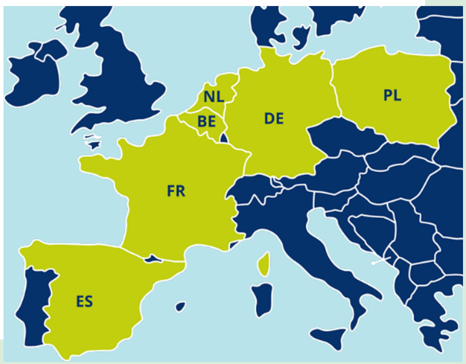
Biomethane from waste

3.4 kt/year bio-LNG

The BioLNG EuroNet project aims to improve the European LNG infrastructure, provide LNG trucks, and produce bio-LNG.

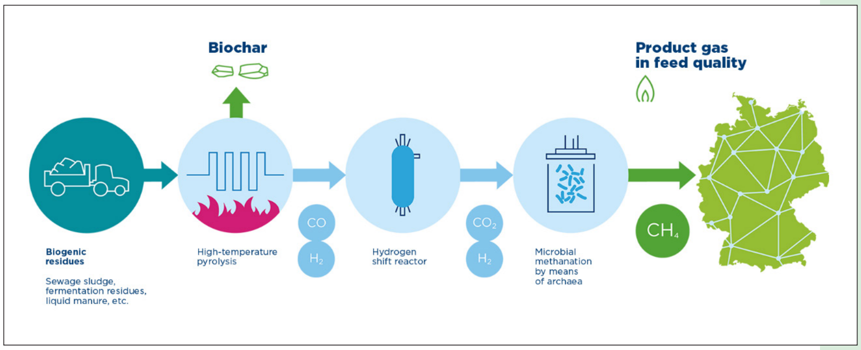
In total, 39 new LNG fuelling stations will be installed in Poland, Germany, the Netherlands, Belgium, France, and Spain along the Trans-European Transport Network. The route from the Atlantic to the Baltic Sea will be connected with an LNG fuelling site approximately every 400 km.

In addition, 2,000 heavy duty LNG trucks are offered by Scania and IVECO. As part of the project setup, a bio-LNG plant was installed by Nordsol in the Netherlands to produce 3.4 ktons of bio-LNG from biomethane out of waste annually. This plant delivered the first bio-LNG in July 2021, and 32 of 39 LNG stations are already in service.



BiRG (BioReststoffGas)

- Goldenstedt, Germany
- OGE, New Power Pack, Forschungszentrum Jülich, Fraunhofer UMSICHT
- Under development, operational in 2022
- Biogenic residues
- 100 m³/h syngas



New Power Pack, Forschungszentrum Jülich, Fraunhofer UMSICHT, and the TSO OGE are building the research project BiRG (BioReststoffGas), a demonstration plant with an input of approximately 300 kg/h that produces approximately 100 m³/h of synthesis gas to support production to test biomethane from biogenic residues. The synthesis gas is produced via high temperature pyrolysis.

In addition to testing a demonstration system capable of permanent loads, alternative process conditions and variants are to be developed for a large number of possible raw materials and raw material combinations.

The plant is scheduled to go into operation in Goldenstedt (Lower Saxony) in the first quarter of 2022.

StrawBerry

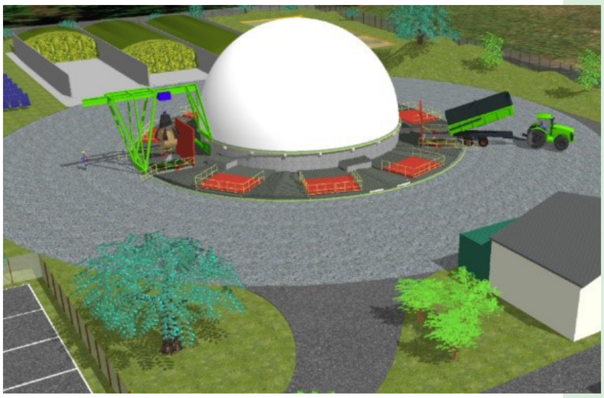
Teréga Solutions is launching the construction of its first methanisation unit based on the innovative concept developed by DualMetha.

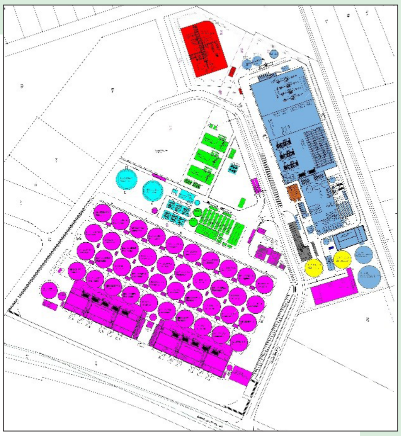
The unit combining liquid and solid AD will be operational in Q4 2022; it will process more than 10,000 tons of agricultural feedstock and more than 1.45 million m³ of biomethane per year. This biomethane will be injected directly into the French gas transportation network.

The total amount of the project is financed up to 70% by Teréga and 30% by four farmers-entrepreneurs involved from the beginning of the development of the project.

The financial innovation proposed by Teréga Solutions is to lease the unit for 15 years at a fixed cost to the farmers through their project company StrawBerry. The farmers keep the operational control of the methanisation unit and reduce their financial exposure.

- Neuvy-Pailloux, France
- Teréga Solutions, DualMetha
- Under development, operational in November 2022
- Energy crops, straw, silage
- 14.5 GWh/year biomethane





NORDFUEL

- Cloppenburg, Germany
- Revis Bioenergy
- Currently under development, operational by 02/2023
- Manure
- 592 GWh/year biomethane

Revis Bioenergy is putting in place a fully circular industrial scale biomethane, Biogenic CO_2 and organic fertiliser production unit in Cloppenburg region.

The unit will produce approximate 125 t/y of liquid biomethane, 178 t/y of dried fertiliser, 43 t/y of liquid fertiliser and 596,000 t/y of clean water. Moreover, it will produce 103 t/y of biogenic liquid CO_2.

The benefits are twofold – both for the farmers economically as well as for societal with the abatement of methane emissions, providing a large societal greenhouse gas savings.

It is the first operation at this large scale in Europe, saving 500,000 tonnes of CO_2 p.a., providing carbon negative fuel for transport or carbon negative fuel to heat homes as replacement for fossil natural gas.

4.2 Hydrogen IPCEIs

AquaVentus

- Helgoland, Germany
- RWE Renewables, GASCADE, and others
- Expected to gradually scale up operations until 2035
- 10 GW offshore wind
- 10 GW offshore electrolysis capacity, 1,000 kt/y of H_2

The AquaVentus initiative aims to install 10 GW of offshore wind with offshore electrolysis in the North Sea between Helgoland and the Dogger Bank sandbank by 2035.

AquaVentus is a consortium made up of 27 leading international companies, organisations, and research institutions. Together the group intends to make a substantial contribution to the implementation of the German and European hydrogen strategy.

A 14 MW prototype of the electrolyser integrated with the wind turbine will be built by 2023, to be expanded in the years after. Pipeline infrastructure to transport the hydrogen to shore is expected to be in place by 2029-2030. By 2035, 1,000 kt/year of green hydrogen could be produced, which will be transported to land via an offshore hydrogen pipeline.

White dragon

The €8 billion White Dragon Project intends to phase out all coal- and lignite-fired power plants by 2028 in the region of Western Macedonia using green hydrogen, in total saving 11.5 $MtCO_2$/year.

The project will produce green hydrogen at a large scale. This green hydrogen will be used in energy storage and reconversion to electricity in high temperature fuel cells as a green base-load cogeneration unit. It will also serve industrial customers. Additionally, electrolyser waste heat will be used as a renewable heat source in local district heating networks.

The project intends to upgrade and capitalise the existing energy infrastructure: electricity grids and natural gas pipelines. Repurposed natural gas pipelines will be used to transport green hydrogen and provide indirect storage.

Western Macedonia, Greece

DEPA, DESFA, and others

Gradual scale up 2022-2029

Solar energy

4.65 GW electrolysis capacity, 250 kt/y of H_2, 400 MW power production

Moreover, the White Dragon Project also aims to develop a complete Hydrogen Industrial Research Center, within the Hydrogen High Technology, Research, Development & Innovation Node.

Green fuels for Denmark

Green Fuels for Denmark is an ambitious vision for the large-scale production of e-fuels using green hydrogen. It has a decarbonisation potential of 850 $ktCO_2$/year.

The project will be built in three phases: 10 MW, 250 MW, and 1,300 MW in total electrolysis capacity. In the first phase, Green Fuels for Denmark will produce hydrogen for heavy duty road transport; in the second phase, renewable hydrogen will be used with carbon capture to produce sustainable methanol for shipping and e-kerosene for aviation.

Ørsted will offtake the power produced at HOFOR's 250 MW Aflandshage offshore wind farm project for the second phase. For the third phase, Ørsted will continue to pursue opportunities to secure additional green power towards the commissioning of the planned energy hub at the Danish island Bornholm. The sustainable carbon/biogenic CO_2 for the e-fuels production will be captured from the 100 MW straw-fired unit at Avedøre Power Station (Bio-CCU).

Copenhagen, Denmark

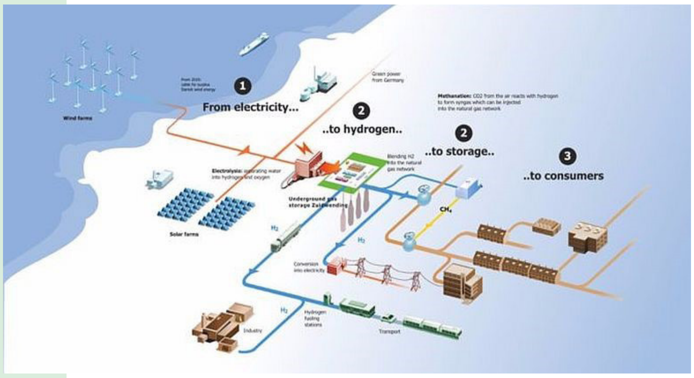
Ørsted, HOFOR, Maersk, and others

First phase expected to be operational by 2025, second phase by 2027

Offshore wind

1.3 GW electrolysis capacity, ~175 kt/y of H_2, 260 MW district heating

HyStock



- Zuidwending, Netherlands
- Gasunie Netherlands
- Expected to be operational in 2026
- 200 GWh hydrogen storage capacity

HyStock is developing a salt cavern for hydrogen storage in Zuidwending near Veendam. There is a need for large-scale underground storage of hydrogen because the supply and demand of hydrogen needs to be balanced, especially with the large amounts of variably produced green hydrogen in the system.

The first salt cavern has a storage capacity of 200 GWh (6,000 tons of hydrogen). If everything goes according to plan, the installation with the first cavern will be operational in 2026. It is expected that by 2030 four caverns for hydrogen storage will be needed to meet the market demand for hydrogen.

McPhy Gigafactory

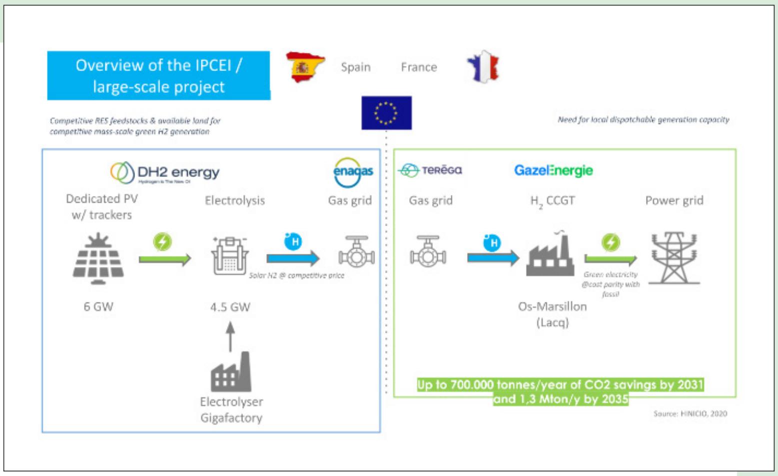
The McPhy Gigafactory combines the development of a new generation of pressurised (~30 bar) alkaline electrolysers and the industrial deployment with mass production.

The objective is to start production in the first half of 2024, with a gradual ramp-up to a capacity of 1 GW per year.

Belfort was preselected as a strategic site, located in the heart of the European hydrogen ecosystem and of the Energy Valley. This future factory will play a major role in the transition to industrial-scale electrolysis, an essential condition for green hydrogen to achieve the decarbonisation objectives set by the French government and the European authorities.

- Belfort, France
- McPhy
- Start electrolyser production in the first half of 2024
- Gradual ramp-up to 1 GW/y pressurized alkaline electrolysers

Lacq Hydrogen



Lacq Hydrogen is part of the wider Spanish Green Crane and HyDeal Ambition projects aimed at producing and exporting competitive green hydrogen from Spain. The project will be a founding block of the European Hydrogen Backbone in the region, trialling hydrogen storage in aquifers and the use of hydrogen in power plants. It aims to accelerate the decarbonisation of industry in the region, with up to 0.7 $MtCO_2$/year savings by 2031 and 1.3 Mt/year by 2035.

Lacq Hydrogen includes the full hydrogen value chain, starting from green hydrogen production using solar PV in Spain at 4.5 GW electrolysis capacity using the excellent solar resources in Spain. Subsequently, the hydrogen will be transported using repurposed gas pipelines and stored underground in aquifers in France. The hydrogen can be reconverted to electricity in a dispatchable combined cycle power plant in the industrial area of Lacq, from 2026 onwards.

GETH2

- Germany
- bp, Evonik, Nowega, OGE, RWE, Salzgitter, Thyssengas
- Gradual scale-up from 2024 to 2030
- 300 MW electrolysis capacity

The GETH2 partners, bp, Evonik, Nowega, OGE, RWE, Salzgitter, and Thyssengas want to build a cross-border full hydrogen value chain—from the production of green hydrogen to transport, storage, and industrial use. By merging the **GET H2 Nukleus and SALCOS project with** the European **Green Octopus** the GETH2 IPCEI was formed. The overall project should be able to avoid CO_2 emissions of up to 16 Mt/year by 2030.

From Lingen to Gelsenkirchen and from the Dutch border to Salzgitter, production, transport, storage and industrial users of green hydrogen are to be connected in several steps between 2024 and 2030: In Lingen, RWE produces green hydrogen via a 100 MW electrolysis plant by 2024. This will be used to supply the bp refinery in Gelsenkirchen. Most of the transport will take place via existing gas grid lines (shown in orange), which will be converted to hydrogen transport. In 2025, it is planned to extend the network to the Dutch border and electrolysis capacity to 200 MW. It will be further extended to 300 MW by 2026, when RWE will integrate a cavern storage facility in Gronau-Epe. By 2030, the network is to be extended to the Salzgitter steelworks and, if necessary, connected to other networks (shown in light blue).

5. National and EU policies on biomethane and hydrogen

5.1 Fit for 55

The **Fit for 55 package** is a comprehensive set of updates to existing laws and new legislative proposals from the European Commission to help achieve the European Union target of 55% greenhouse gas (GHG) emissions reduction by 2030 compared to 1990 (the previous target was 40%). This package will have an immense impact on the decarbonisation of the EU economy.

The Fit for 55 package, among others, contains:

- 50% renewable hydrogen target by 2030 for all hydrogen used in industry, which could lead to 90 TWh/year of hydrogen demand by 2030,
- 1.1% per annum increase of renewable energy sources share in the heating & cooling sector,
- 2.6% share of final energy demand in transport was set for RFNBOs and a minimum of 0.7% of synthetic kerosene in final energy demand in aviation, which could lead to 87 TWh/year of hydrogen demand by 2030 (of which 7 TWh/year in aviation),
- 6% GHG emissions intensity reduction target for onboard fuels of by 2030 for the maritime sector, non-fuel specific, which could correspond with a hydrogen demand of 29 TWh/year.

The Gas for Climate consortium has previously called on the Commission to add a binding 11% renewable gas target to the recast Renewable Energy Directive (RED II)—8% for biomethane and 3% for green hydrogen.[141] We estimate that the current Fit for 55 package could achieve a 9.4% renewable gas share by 2030—5.1% biomethane and 4.3% green hydrogen (renewable fuels of non-biological origin, or RFNBOs).[142]

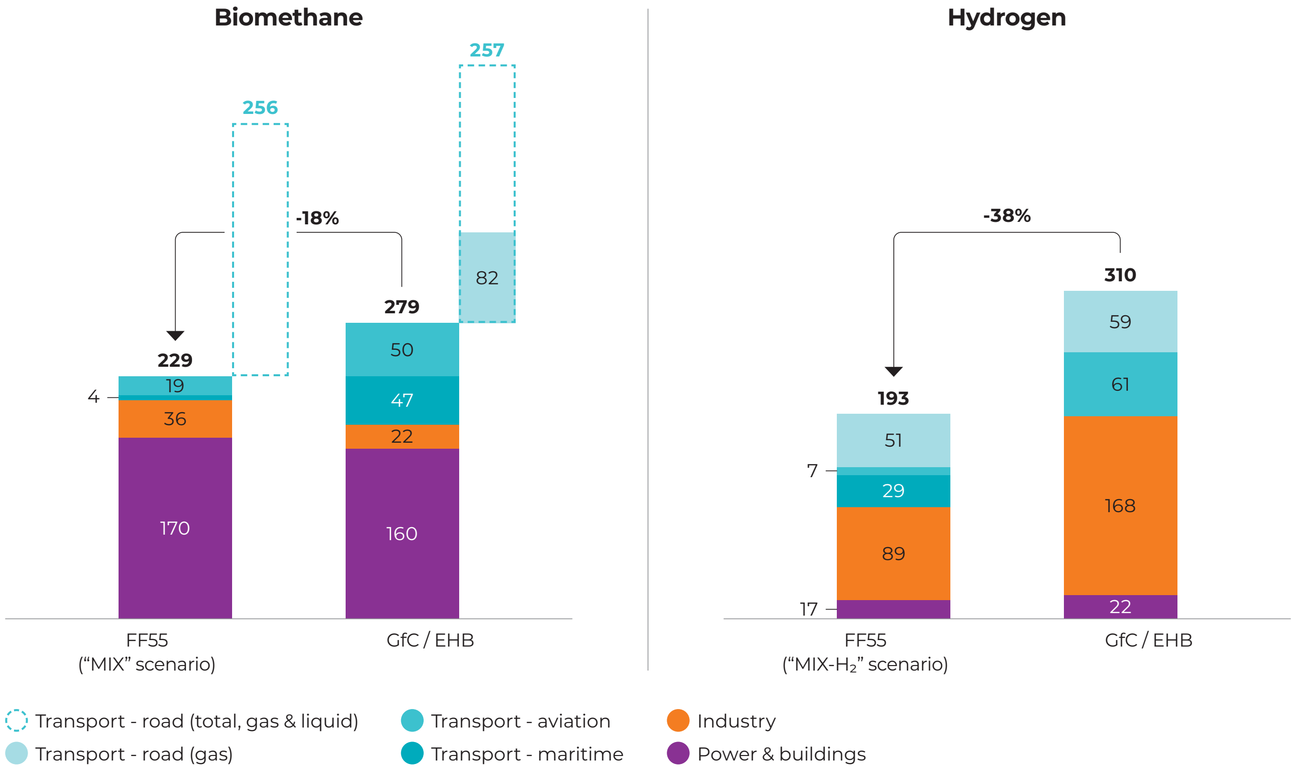
These shares correspond to around 279 TWh of biomethane across power and buildings, industry, aviation, and maritime in the GfC scenario, compared to 229 TWh in the Commission's scenario.[143] Thus, GfC forecasts around 18% higher demand for biomethane by 2030 than the Commission (excluding road transport demand).

For hydrogen, the MIX-H_2 scenario adds up to approximately 193 TWh of hydrogen (RFNBO only) demand compared to the GfC estimation of 310 TWh, a difference of around 38%. The GfC scenarios rely on a combination of green and blue hydrogen, making a direct comparison here less precise.

The **full analysis** of the Fit for 55 proposals including a set of **key policy recommendations** to accelerate the development of renewable and low-carbon gases in Europe and the energy transition can be found on the gas for climate website.

141 Share of total gas consumption (natural gas, low-carbon gases, renewable gases), with 8% coming from biomethane and 3% from green hydrogen (no multipliers). This would result in around 360 TWh of biomethane and 140 TWh of green hydrogen.
142 Derived from our calculations based on the MIX scenario (approximately 17% decline in natural gas consumption between 2020 and 2030).
143 These figures exclude the demand for biofuels in road transport because the available results for the MIX scenario do not distinguish between gaseous and liquid biofuels, whereas GfC estimates only gaseous biofuels (82 TWh, including bio-liquified natural gas (LNG)).

Figure 19
Comparison of gaseous biofuel and hydrogen volumes across all end-use sectors between the Commission's MIX (and MIX-H_2) modelling scenario and the GfC/European Hydrogen Backbone (EHB) scenarios (TWh), for 2030



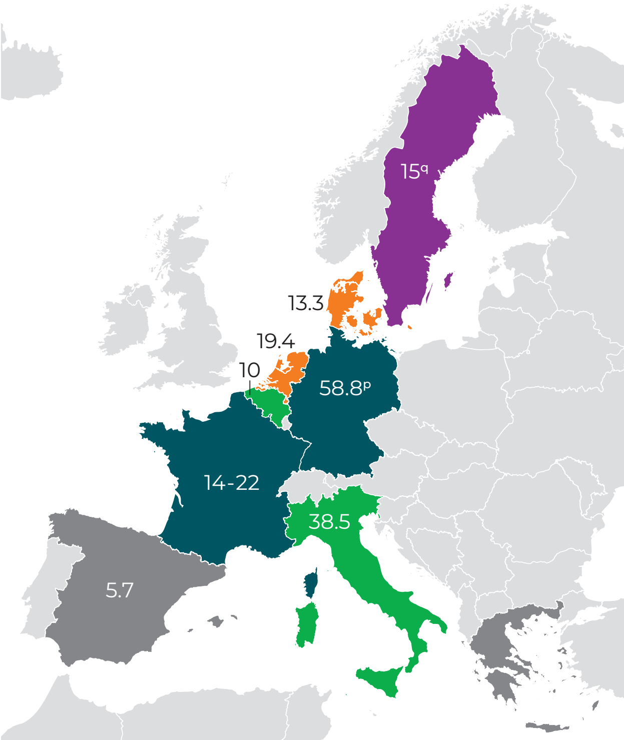
Note: Dashed box [transport – road (total)] includes non-gaseous bioenergy.

5.2 Overview of national strategies and targets

The European and national biomethane and hydrogen strategies and support mechanisms are briefly described in this section. There are large differences in the strategies and support, which will influence the national development. Because biomethane is being used more widely across Europe, biomethane support is more detailed, whereas mainly production targets are published for hydrogen. Figure 20 illustrates the different types of operational support schemes for biomethane and their production target (binding or not-binding). Spain and Greece do not have a support scheme in place. Other countries use different support schemes based on feed-in tariffs and premiums, fiscal incentives, or a quota system. The different types of support mechanisms are explained below in detail for each country.

Figure 21 shows the national hydrogen strategies and electrolysis targets by 2030. The combined strategies with electrolysis targets set by Member States add up to around 40 GW in the EU by 2030, already more than the 42 GW target set by the European Commission, while several EU member states have not yet published targets.

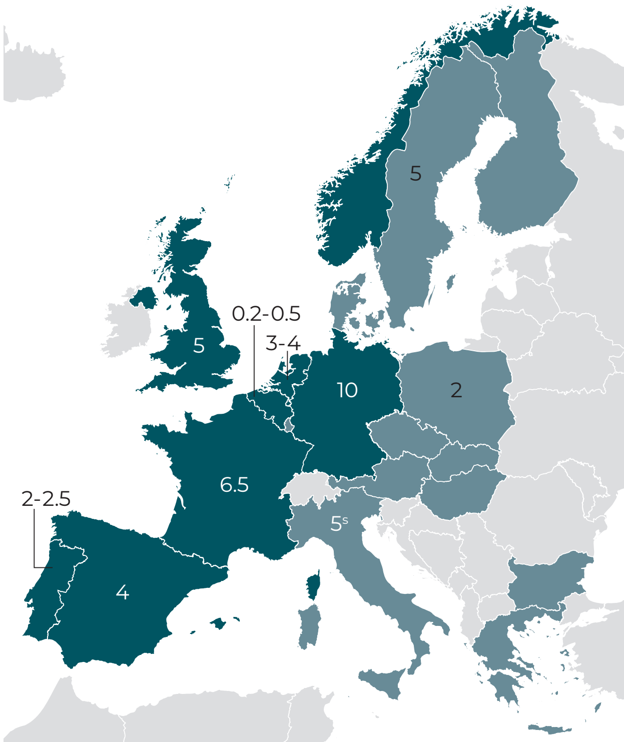
Figure 20
Overview of national biomethane operational support schemes in 2021 in TWh (Regatrace, adapted)[144]



- Quota System[l]
- Feed-in premium[m]
- Feed-in tariff[n]
- Fiscal incentives[o]
- No support
- Out of scope

l obligatory target stating a specific share of biomethane.
m bonus (fixed or flexible) paid on top of market price.
n fixed guaranteed price.
o tax (e.g. carbon tax) incentives for biomethane technologies.
p Biomass: Germany has a 8.4 GW biomass production target, a load factor of 0.8 was assumed.
q Biogas: Sweden only has a biogas target.

Figure 21
National hydrogen strategies per EU member state and national electrolysis targets in GW by 2030



- H_2 strategy adopted
- H_2 strategy in development

r Spanish and Italian figures refer to mobilised investments while German and French figures refer to spent public funds.
s Figures according to National Hydrogen Strategy Preliminary Guidelines.

144 REGATRACE, *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.

5.3 Summary of biomethane and hydrogen strategy per country

5.3.1 EU

Biomethane

The European targets for biomethane are part of RED II. Until 2030, EU Member States should raise the share of renewable energy in the heating and cooling sector by 1.3% annually. Biogas and biomethane can form a large part of that.

In the transport sector, the fuel suppliers are asked to ensure a share of 14% renewable energy in the total consumption by 2030. Biogas and biomethane can count towards this target and towards the specific subtargets of 3.5% on advanced biofuels and biogas.[146, 147]

There is no explicit biomethane target. In a policy paper, Gas for Climate suggested that, to stimulate the biomethane market development, a binding target for biomethane consumption be introduced and set to 8% in 2030.[148]

Hydrogen[145]

The European Hydrogen Strategy from 2020 sets out the goal, in a first phase through 2024, to install at least 6 GW of electrolysers in the EU and the production of up to 1 million tonnes of renewable hydrogen. In a second phase, from 2025 to 2030, the EU sets out the goal for hydrogen to become an intrinsic part of an integrated energy system. For this second phase, there is a strategic objective to install at least 40 GW of electrolysers by 2030, and the production of up to 10 million tonnes of renewable hydrogen in the EU.

To support the envisioned electrolyser deployment, several EU funds (e.g. InvestEU, European Regional Development Fund, Cohesion Fund) are available. The sustainable finance taxonomy will further guide investments into hydrogen.

The recent Fit for 55 package proposed multiple measures to accelerate the renewable hydrogen market (see Chapter 5.1).

5.3.2 Belgium

Biomethane

In Belgium, there are no targets for the production of biomethane. However, according to Gas.be, the 2021 biomethane potential based on available feedstocks in Flanders is 8 TWh and in Wallonia it is 7 TWh. In 2030, 5 TWh of biomethane is expected to be produced per region if suitable measures are implemented.[150]

continue on next page →

Hydrogen[149]

In the Belgian COVID-19 recovery plan, a hydrogen production target of 150 MW by 2026 has been determined. The region of Flanders published a hydrogen strategy in which it expresses the ambition to become the European leader in hydrogen.[153]

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145 European Commission, *A hydrogen strategy for a climate-neutral Europe*, 8 July 2020, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.
146 EU Science Hub, "Renewable Energy – Recast to 2030 (RED II)," European Commission, accessed 10 Ocotber 2021 https://ec.europa.eu/jrc/en/jec/renewable-energy-recast-2030-red-ii.
147 21.12.2018 L 328/125 Official Journal of the European Union EN, December 2018.
148 Guidehouse, *Setting a binding target for 11% renewable gas*, policy paper prepared on behalf of Gas for Climate, January 2021, https://gasforclimate2050.eu/wp-content/uploads/2021/01/Gas-for-Climate-Setting-a-binding-target-for-11-renewable-gas.pdf.
149 Martens, P., "Belgian hydrogen projects amongst the most mature in Europe," Agoria, 29 June 2021, https://www.agoria.be/en/infrastructure/energy/belgian-hydrogen-projects-amongst-the-most-mature-in-europe
150 Climact, Study 2021 on Biomethane in Belgium, prepared on behalf of Gas.be.

The support scheme depends on the region in Belgium. In Flanders, there is a limited investment support for biomethane production through AD upgrading or gasification. The support is limited by the size of the enterprise. While small enterprises can apply for 65% of investment support, large enterprises can just apply for 45%. The support is capped at €250,000 per project. There is no operational support to be added.[151]

In Wallonia, the investment support is lower, with a maximum of 27.5% funded. The operational support is much stronger. This support scheme is based on guarantees of origin (GoOs) and a quota system for energy suppliers. The GoOs can only be received by plants based in Wallonia and injected into the gas grid. These GoOs can be sold to CHP plants in Wallonia at a current price of €75/MWh. For CHP plants who have bought GoOs, there is financial support as well.[152]

Belgium is part of the European IPCEI Hydrogen consortium and 25 Belgian companies (15 direct and 10 indirect participants) were selected by the federal and regional governments. The Flemish government decided to make more than €100 million available for IPCEI Hydrogen projects and utilise direct subsides (instead of repayable advances).

Flanders is also looking into other hydrogen support options. It is considering using the revenue from the kilometre tax on lorries for investments for heavy transport applications (trucks, buses, forklifts, and refuse collection trucks running on hydrogen or methanol). In addition, Flanders will work with private stakeholders to identify the obstacles in the legislative and regulatory framework for the further rollout of hydrogen technology.

5.3.3 Denmark

Biomethane

Denmark does not have a binding biomethane strategy, although there is a roadmap developed by energy corporations and the Danish government. This roadmap states that the biogas production of 4.4 TWh (2019) has to be built out to 13.3 TWh by 2030. While today 58% of the biogas is upgraded to biomethane, the total new build-out has to deliver upgraded biomethane. Biomethane is expected to be used primarily in industry and for heat and power production.[154]

The Danish subsidy system is based on feed-in premiums. In 2018, the base subsidy was €39/MWh for grid injection of biomethane. Additionally, a premium is implemented, which is adjusted to the gas price. This allows biogas production, even at low gas prices.[155]

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Hydrogen

Denmark's national hydrogen strategy is under development and is expected to be released by the end of 2021.

The Danish national hydrogen organisation, Hydrogen Denmark, has published its own hydrogen strategy, which is meant to inspire the Danish national strategy.[157] The hydrogen industry proposes that from the Next Generation EU funds that Denmark receives, at least DKK 5 billion is invested into hydrogen and PtX in Denmark.

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151 REGATRACE, *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.
152 REGATRACE, *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.
153 The Flemish Minister of Economy, Innovation, Work, Social Economy and Agriculture, "Flemish Hydrogen Vision 'European frontrunner through sustainable innovation,'" https://www.ewi-vlaanderen.be/sites/default/files/bestanden/5fad5387b328e9000c00018b.pdf.
154 Danish Climate Partnership for the Energy and Utilities Sector, *Powering Denmark's Green Transition: Roadmap for a near carbon neutral energy sector to achieve Denmark's 70% reduction target by 2030*, May 2021, https://www.danskenergi.dk/sites/danskenergi.dk/files/media/dokumenter/2020-05/Powering_Denmarks_Green_Transition_Climatepartnership_.pdf.
155 Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), *Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy*, Ifri, April 2019, https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf.

A new subsidy scheme is being implemented. Because the old system was not capped, the subsidy costs increased to €215.4 million in 2017. Hence, the new subsidy system consists of a pool of €32 million annually, which will be assigned in tenders. It can be expected that the new subsidy system will slow down the current biogas build-out, while also lowering production costs with increased competition.[156]

Energinet, the Danish national TSO for electricity and natural gas, developed a PtX Action Plan to set out Energinet's role in the implementation and wider diffusion of the technology according to several guiding principles.[158]

5.3.4 France

Renewable gases injected in the grid should reach 10% by 2030.

Biomethane

The French biomethane strategy is part of the Multiannual Energy Plan, which was published in 2018 and updated in 2020. It is a roadmap to 2028. The main biomethane target is to increase production for grid injection to 6 TWh in 2023 and up to 14 to 22 TWh in 2028 (6% - 8% of total gas consumption).[160]

For grid injection of biomethane, there is a feed-in tariff, which varies between €60/MWh and €120/MWh according to the plant size. A premium can be added for some feedstocks like manure.[161] The plan is to reduce the maximum tariff to €87/MWh in 2023 and €80/MWh in 2028.[162]

Due to strong support in previous years, the targets are likely to be reached. The current biomethane injection capacity is at 5 TWh, and there are projects of around 20 TWh under development.[163]

Hydrogen[159]

The national strategy to develop decarbonised and renewable hydrogen in France sets out the goal to have 6.5 GW of electrolysers installed by 2030.

To support the development of a French electrolysis sector, the government will set aside €1.5 billion to be invested into, for example, an IPCEI on hydrogen. To speed up the development of the French hydrogen production sector, the strategy offers a set of tools to make it possible to develop high capacity projects thanks to visibility on demand and the move to industrial scale to achieve profitability.

To speed up the decarbonisation of French industry, the strategy offers a set of tools to make production by electrolysis reliable, to adapt and develop industrial processes, and to support these solutions (both for investment and during the operation of facilities) as long as the price of hydrogen is not competitive with carbon solutions. The government plans to set up a GoO mechanism to add value to decarbonised hydrogen against hydrogen produced from fossil fuels. It also plans to develop a compensation mechanism to support investment and operations after calls for tenders.

156 Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), *Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy.*
157 Brintbranchen, "New report: Hydrogen and Power-to-X can give Denmark a new growth and export adventure," https://brintbranchen.dk/brint-og-power-to-x-kan-give-danmark-nyt-vaekst-og-eksporteventyr/.
158 Energinet, *Winds of Change in a Hydrogen Perspective*, November 2019, https://en.energinet.dk/-/media/4385D-B7A333248E7A1A3EA8674E460DA.PDF.
159 French Government (2020). National strategy for the development of decarbonised and renewable hydrogen in France .https://www.bdi.fr/wp-content/uploads/2020/03/PressKitProvisionalDraft-National-strategy-for-the-development-of-decarbonised-and-renewable-hydrogen-in-France.pdf
160 French Ministry of Ecological Transition, *Executive Summary – French Strategy for Energy and Climate, Multiannual Energy Plan, 2019-2023, 2024-2028*, https://www.ecologie.gouv.fr/sites/default/files/PPE-Executive%20summary.pdf.
161 REGATRACE, *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.
162 French Ministry of Ecological Transition, *Executive Summary – French Strategy for Energy and Climate, Multiannual Energy Plan, 2019-2023, 2024-2028*, https://www.ecologie.gouv.fr/sites/default/files/PPE-Executive%20summary.pdf.
163 Terega, interview

5.3.5 Germany

Biomethane

The biomethane support and targets are implemented in the Erneuerbare-Energien- Gesetz (EEG) in Germany. Since the EEG 2014, there are no binding targets for grid injection of biomethane. In the EEG 2021, the overall target is for biomass to achieve 8.4 GW of production power by 2030, including biogas and biomethane.

The subsidy scheme implemented in the EEG 2021 is based on a tender system, with maximum feed-in tariffs for electricity produced of €16.4/MWh for new plants and €18.4/MWh for existing plants. The tender volume is set to a total plant size of 600 MW per year (200 MW in EEG 2017). Starting in 2022, there is a quota that at least 50% of plants have to be built in southern Germany and 150 MW/y of flexible biomethane CHP plants are put out for tender.[165]

Because the feed-in tariffs are limited to low prices, the tender volumes of 600 MW/y and the target of 8,400 MW in 2030 are not expected be achieved.[166] This development was observed in the first tender round, where the total tender volume was 168 GW but just 34 GW of biomass plants were funded because not enough plants applied.[167]

Hydrogen[164]

According to the National Hydrogen Strategy, the German government expects that around 90-110 TWh of hydrogen will be needed by 2030. To cover part of this demand, Germany plans to produce up to 5 GW of generation capacity, including the offshore and onshore energy generation facilities needed for this. This corresponds to 14 TWh of green hydrogen production and will require 20 TWh of renewables-based electricity. An additional 5 GW of capacity is to be added, if possible, by 2035 and no later than 2040.

As part of Germany's decarbonisation programme, funding is provided to invest in technologies and large-scale industrial facilities that use hydrogen to decarbonise their manufacturing processes. More than €1 billion will be provided for this between 2020 and 2023. There are also programmes that promote the use of hydrogen in manufacturing. These seek to encourage the industry to invest in hydrogen solutions. On 3 June 2020, the Coalition Committee adopted a package for the future that makes another €7 billion available to speed up the market rollout of hydrogen technology in Germany and another €2 billion to foster international partnerships.

Germany is also exploring potential tendering schemes to produce green hydrogen, e.g. to help decarbonise the steel and chemical industries. If necessary, the financing that has been earmarked for the National Decarbonisation Programme will be topped up as needed.

164 Federal Ministry for Economic Affairs and Energy Public Relations Division, *The National Hydrogen Strategy*, June 2020, https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.pdf?__blob=publicationFile&v=6.
165 FNR, "EEG 2021- New framework for biogas plants," https://biogas.fnr.de/rahmenbedingungen/eeg-2021.
166 Neumann, H., "Tender: EEG 2021 hits the biogas industry with full force," top agrar, 30 April 2021, https://www.topagrar.com/energie/news/ausschreibung-eeg-2021-trifft-die-biogasbranche-mit-voller-wucht-12558112.html.
167 Clearingstelle, "Results of the first round of tenders for biomass plants in 2021," https://www.clearingstelle-eeg-kwkg.de/ausschreibung/5984.

5.3.6 Greece

Biomethane

No biomethane strategy.

Hydrogen

Greece's hydrogen plans are still at an early stage. Hydrogen-related legislation is expected in late 2021 or early 2022.

5.3.7 Italy

Biomethane

The 2018 Biomethane Decree set targets for the production of biomethane, limited to the transportation sector. The aim is to achieve 1.1 bcm/y of biomethane by 2022,[169] which is the current consumption of natural gas in road transport. Furthermore, quotas for biofuels are implemented. From 2021, the share of biofuels has to be 10.0%. From 2023, for advanced biofuels, the quota is 3%, of which 2.25% has to be supplied by advanced biomethane and 0.75% by other advanced biofuels.[170]

The subsidy scheme assigns €4.7 billion between 2018 and 2022. The support mechanism is based on a quota system for biofuel obligations and certificates of release for consumption (Certificati di Immissione in Consumo di biocaruranti, CIC). These CICs are allocated to producers of biomethane and can be sold to fuel suppliers bounded to biofuel quotas.[171, 172]

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Hydrogen[168]

In November 2020, the Ministry of Economic Development published the first Guidelines for the National Hydrogen Strategy (Linee Guida per la Strategia nazionale sull'idrogeno – the Guidelines), identifying the sectors in which green hydrogen is expected to become competitive in the short term.

The guidelines expect up to €10 billion of investments for hydrogen (renewable energy source investments to be added), with half of the amount coming from European funds and private investments. This amount includes investments in hydrogen production (€5-€7 billion), hydrogen distribution and consumption facilities (hydrogen-powered trains and trucks, refuelling stations, etc.) (€2-€3 billion), research and development (€1 billion), and infrastructure (such as gas networks) to properly integrate hydrogen production with end uses. These investments do not include the €2 billion to be allocated to develop the hydrogen supply chain within the framework of the Next Generation EU initiative to alleviate the economic impact of the COVID-19 pandemic on the national economy.

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168 Ministry of Economical Progress, *National Hydrogen Strategy: Preliminary Guidelines*, November 2020, https://www.mise.gov.it/images/stories/documenti/Strategia_Nazionale_Idrogeno_Linee_guida_preliminari_nov20.pdf.
169 The 2022 deadline should be postponed to 2026 by the Decree of RED II (see: Legislative decree implementing Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources (292) Articles 1 and 5 of the law of 22 April 2021: http://documenti.camera.it/apps/nuovosito/attigoverno/Schedalavori/getTesto.ashx?file=0292.pdf&leg=XVIII#pagemode=none).
170 Ministry of Economical Progress, *Ministerial Decree 30 December 2020 - Biofuels (amendment to Ministerial Decree 10 October 2014*, https://www.mise.gov.it/index.php/it/89-normativa/decreti-ministeriali/2041856-decreto-ministeriale-30-dicembre-2020-bio-carburanti-modifica-al-dm-10-ottobre-2014.
171 Marc-Antoine Eyl-Mazzega and Carole Mathieu (eds.), *Biogas and Biomethane in Europe: Lessons from Denmark, Germany and Italy*, Ifri, April 2019, https://www.ifri.org/sites/default/files/atoms/files/mathieu_eyl-mazzega_biomethane_2019.pdf.
172 REGATRACE, *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.

Since the production target is going to be achieved shortly, a new Biomethane Decree is being developed to include other sectors beyond transportation. The new incentive mechanism is expected by the end of 2021 to promote the production of a further 2.3-2.5 bcm/y of biomethane to decarbonise the industrial sector (hard to abate) and the residential sector. The mechanism aims to stimulate the production of biomethane from the agricultural sector and will promote the conversion of existing biogas plants and the construction of new ones.

Italy plans to install approximately 5 GW of electrolysis capacity to produce hydrogen. The current regulatory framework for hydrogen production in Italy refers only to the production of hydrogen using fossil fuels, with repercussions (e.g. lengthy and burdensome administrative procedures) on investors in green hydrogen.

5.3.8 Netherlands

Biomethane

In the Netherlands, the Climate Agreement from June 2019 plans to realise 70 PJ/y (19.44 TWh/y) of green gases in 2030, equal to 5.4% of the total gas demand in 2017.[174] In March 2020, The Minister of Economic Affairs presented the Cabinet Vision on green gas[175]. In line with the Climate Agreement, the vision forms the basis for realising the 70 PJ ambition.

The biomethane target will be supported by the Stimulation of Sustainable Energy Production and Climate Transition (SDE++) subsidy scheme. The funding system is based on feed-in-premiums distributed through an application system. The amount of premium received depends on the feedstock used and the amount of CO_2 reduced. In 2020, the premium was between €30.0/MWh (sewage treatment plant) and €79.0/MWh (biomass gasification).[176]

Hydrogen[173]

The Climate Agreement from June 2019 plans to install around 500 MW by 2025 and 3 GW-4 GW of electrolyser capacity by 2030. In March 2020, the Minister of Economic Affairs presented the cabinet vision on hydrogen.[177] In line with agreements in the Climate Agreement, the vision will form the basis for a national hydrogen programme.

The cabinet vision presents support schemes for the different stages of development. The government supports applied research and development of production in the various MOOI tenders. In addition, innovative pilots in hydrogen are stimulated via the DEI+. The government will contribute an additional €30-€40 million per year for demo facilities and pilots from the Climate Envelope funds for industry and electricity, where possible, through existing schemes and funding opportunities. Inclusion in the SDE++ support scheme will be considered as soon as hydrogen is competitive in terms of cost with other options in the scheme.

173 Dutch Government (2019). *Climate agreement: Chapter Hydrogen* https://www.klimaatakkoord.nl/binaries/klimaatakkoord/documenten/publicaties/2019/06/28/klimaatakkoord-hoofdstuk-waterstof/klimaatakkoord-c5-7+Waterstof.pdf
174 Climate Agreement, Netherlands.
175 Ministry of Economics and Climate, "Green Gas Roadmap," 20 March 2020, https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/kamerstukken/2020/03/30/kamerbrief-routekaart-groen-gas/kamerbrief-over-routekaart-groen-gas.pdf.
176 Netherlands Enterprise Agency, *SDE++ 2020: Stimulation of Sustainable Energy Production and Climate Transition*, November 2020, https://english.rvo.nl/sites/default/files/2020/11/Brochure%20SDE%20plus%20plus%202020.pdf.
177 Ministry of Economics and Climate, "Concerns Cabinet Vision on Hydrogen," https://www.rijksoverheid.nl/binaries/rijksoverheid/documenten/kamerstukken/2020/03/30/kamerbrief-over-kabinetsvisie-waterstof/Brief+kabinetsvisie+waterstof+.pdf.

5.3.9 Spain

Biomethane

The biogas roadmap is still under consultation but will be launched in 2021. The main goal is to boost the production and consumption of biogas and biomethane in the short and medium term. Biomethane should mainly be used in the heavy duty transportation sector and as substitution for natural gas in the grid. The main drivers for the biomethane uptake should be regulatory instruments (GoO), sectoral instruments (penetration targets), economic instruments (tax improvements, financial support), transversal instruments (prioritisation of biomethane project), and promotion of Research, development and innovation(RD&I).[179]

It is expected that the biogas roadmap as proposed will increase the biogas production from 3.8 TWh to 10.4 TWh in 2030, where 55% would be upgraded to biomethane.[180]

Hydrogen[178]

The Spanish Vision 2030 expects an installed capacity of 4 GW of electrolysers and a series of milestones in the industrial, mobility, and electricity sectors; for this vision, it will be necessary to mobilise investments estimated at €8,900 million from 2020 to 2030. However, as an intermediate milestone to reach the 4 GW objective, it is estimated that by 2024 it would be possible to have an installed power of electrolysers between 300 MW and 600 MW.

Spain seeks to support renewable hydrogen through administrative simplification, public utility direct lines/hydro pipelines, and a renewable hydrogen GoGO system.[181]

In November 2020, the government announced that it would allocate €1.5 billion to boost the use and production of renewable hydrogen by 2023 through Next Generation EU.

5.3.10 Sweden

Overall Target: Energy gases fossil-free in 2045

Biomethane

In Sweden no binding targets or strategies are implemented for biogas or biomethane, although there is a proposal for a National Biogas Strategy 2.0 launched by Energigas, the Swedish gas industry organisation. According to this strategy, the biogas production in Sweden in 2030 should be above 15 TWh, while 12 TWh should be used in the transport sector and 3 TWh in industry.

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Hydrogen

The Swedish government has ordered the Swedish Energy Agency to produce a national hydrogen strategy, which is expected to come in November 2021. The goal of the strategy and proposed measures is to develop and take advantage of the opportunities with hydrogen and electric fuels and facilitate the transition to fossil-free.[185]

continue on next page →

178 Ministry for the Ecological Transition and the Demographic Challenge, Executive Summary: https://www.miteco.gob.es/images/es/h2executivesummary_tcm30-513831.pdf.
179 The News 24, "The Government launches the roadmap to promote biogas in Spain," 15 July 2021, https://www.then24.com/2021/07/15/the-government-launches-the-roadmap-to-promote-biogas-in-spain/.
180 Hoja du Ruta Biogás (Borrador)
181 Ministry for the Ecological Transition and the Demographic Challenge, *Hydrogen Roadmap*, 14 October 2020, https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/events/presentations/02.03.02_mf34_presentation-spain-hydrogen_roadmap-cabo.pdf.

The current support scheme in Sweden primarily works through fiscal incentives. The use of renewable or green gases (proven with GoO from the national biogas registry by the Swedish Energy Agency) leads to CO_2 and energy tax exemptions. In comparison to petrol, the tax reduction is €74/MWh. Additionally, there is production support for biogas from manure (€20/MWh) and for biomethane upgrading (€26/MWh), except from sewage sludge, landfill, food, or feed crops.[182, 183]

The current support scheme is often criticised because it leads to doubled subsidies for biogas imported into Sweden from Denmark.[184]

The government initiative Fossil Free Sweden has published a proposal for a hydrogen strategy and proposed that the government should, by 2022, set a planning goal to have 3 GW installed electrolysis power by 2030 and at least 8 GW by 2045 to enable fossil-free development in most sectors.[186] Fossil Free Sweden also suggests carrying out a fast-track study on production support for fossil-free hydrogen projects during an introductory phase through the Carbon Contract for Difference. The government should also instruct the Swedish Energy Agency to draw up a call for proposals for regions in Sweden as a demo to test and demonstrate cross-sectoral hydrogen systems. The aim is to establish a couple of Swedish hydrogen clusters (Hydrogen Valleys).

182 Klackenberg, L., *Biomethane in Sweden – market overview and policies*, The Swedish Gas Association, 16 March 2020, https://www.energigas.se/media/boujhdr1/biomethane-in-sweden-210316-slutlig.pdf.

183 Klackenberg, L., *National Biogas Strategy 2.0*, The Swedish Gas Association, April 2018, https://www.energigas.se/media/boujhdr1/biomethane-in-sweden-210316-slutlig.pdf.

184 REGATRACE, *D6.1 Mapping the state of play of renewable gases in Europe*, 6 April 2020, https://www.regatrace.eu/wp-content/uploads/2020/04/REGATRACE-D6.1.pdf.

185 Government Offices of Sweden, "The government is developing a national hydrogen strategy," 3 February 2021, https://www.regeringen.se/pressmeddelanden/2021/02/regeringen-tar-fram-nationell-vatgasstrategi/.

186 Fossil Free Sweden, *Strategy for fossil free competitiveness – Hydrogen*, 2021, https://fossilfrittsverige.se/wp-content/uploads/2021/01/Hydrogen_strategy_for-_fossil_free_competitiveness_ENG.pdf

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