Gas for Climate

Gas decarbonisation pathways 2020–2050

Appendix

April 2020

GAS FOR CLIMATE
A path to 2050

Guidehouse

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1. Biomethane Deployment Pathways

Key Takeaways

- EU biomethane production is small today, yet a significant sustainable potential exists for 2050. Current EU policies are insufficient to fully unlock this potential.
- Biomethane producers and energy companies should strive to bring down production costs, scale-up the size of biogas digesters, and invest in large-scale biomass gasification units. This requires additional policy incentives plus the creation of an international marketplace.
- Unlocking the full potential of sustainable biomethane depends on the extent to which investments in production capacity can be mobilised and the extent to which sustainable feedstock supply can be ensured, including through a scale-up of whether sequential cropping can be scaled up. Farming associations should pilot-test sequential cropping across Europe the Biogasdoneright concept outside of Italy and set up training and awareness raising programmes among farmers.

1.1 Introduction to Gas for Climate analysis

Biomethane has similarities to natural gas. It can be blended at any percentage with natural gas and transported, stored, and distributed through existing gas infrastructure provided that impurities are removed and biomethane is produced within the specifications determined at European level.[1] Biomethane can be produced through two main technologies, anaerobic digestion and biomass-to-biomethane gasification. The first is widely used today to produce biogas from agricultural biomass. This biogas can be upgraded to biomethane for which multiple upgrading technologies exist and are being used today. Gasification can produce biomethane from woody and lignocellulose biomass. This production route is not yet implemented at commercial scale, although several large demonstration plants have been built.[2]

1.1.1 Current situation of biomethane

Europe has seen a steady growth in the number of biogas plants over the past decade. Most biogas plants are used to produce electricity and heat while a growing share is used to generate biomethane. In 2018, about 18,000 biogas plants and 610 biomethane plants were in operation across Europe. The installed electricity capacity from biogas plants reached a total of just over 11,000 MW in 2018, at an average of 0.6 MW_e per plant.[3] The electricity generated by these plants amounted to 65 TWh_e. With average electrical efficiency of 38%, this means an input of 171 TWh biogas (16 bcm in natural gas equivalent). Biomethane increased to 19 TWh (2 bcm natural gas equivalent) in 2017.

The cost of producing biomethane from anaerobic digestion largely depends on feedstocks used and plant size; it varies between €70/MWh and €90/MWh (€0.65/m^3 to €0.90/m^3) on average in 2020. Thermal gasification for biomethane synthesis is in the early commercial stage of development. Currently, some 50 to 100 biomass or waste gasifiers are in operation globally, but none (or hardly any) produce biomethane.[4] In the EU, there are a few pilots on gasification-based biomethane. The GoBiGas project (20 MW_{th}), was the first ever large-scale demonstration gasification plant and went on-stream in Sweden in 2013. However, the project was terminated in 2018 because it was outcompeted by cheaper biomethane from anaerobic digestion.[5] Other biomass-to-biomethane gasification processes are being pilot tested as well, including supercritical water gasification and hydrothermal gasification. Production costs are relatively high today, estimated to be around €100/MWh (€1.0/m^3).[6,7] Costs could come down if large facilities are deployed. For large-scale production, forestry residues, waste wood, and solid wastes are the most relevant feedstock types.

Biomethane faces numerous barriers for its scale-up, including the lack of proper incentives for production and use, little or no local and regional coordination for biomass procurement, low carbon price, partial coverage of end-use sectors in the EU emissions trading system (EU ETS), and limited implementation of waste hierarchy across member states.

1.1.2 Biomethane in 2050 based on the Gas for Climate Optimised Gas scenario

The Gas for Climate 2019 study analysed a bottom-up biomethane potential based on biomethane that can be collected within the EU. The study assumed that roundwood would be harvested for uses such as timber, pulp and paper instead of for biomethane. The primary agricultural crops are assumed to be used for food and animal feed, not for biomethane. Biomethane would be produced from low ILUC risk waste, residue, and additional second crops. The study concluded that it would be possible to produce 95 bcm of biomethane in natural gas equivalent, or 1,020 TWh/year by 2050. This total potential consists of 62 bcm (660 TWh) produced through anaerobic digestion and 33 bcm (350 TWh) produced through (thermal) gasification. Out of the 62 bcm from anaerobic digestion, some two-thirds would be produced from low indirect land use change (ILUC) risk second crops and some 22 bcm would be produced from (agricultural) wastes and residues.

1 CEN developed a standard for biomethane specification to enable its injection in gas grids, published in 2016: https://standards.cen.eu/dyn/www/f?p=204:32:0::::FSP_ORG_ID,FSP_LANG_ID:853454,25&cs=1A6E2885FFA69ED2A8C4FA137A6CEF3DA

2 For example, a 20 MW biomethane thermal gasification plant in Göteburg, Sweden ('GoBiGas') and a similar sized supercritical water gasification facility in Alkmaar, the Netherlands ('SCW systems').

3 EBA Annual Report 2019. https://www.europeanbiogas.eu/wp-content/uploads/2020/01/EBA-AR-2019-digital-version.pdf

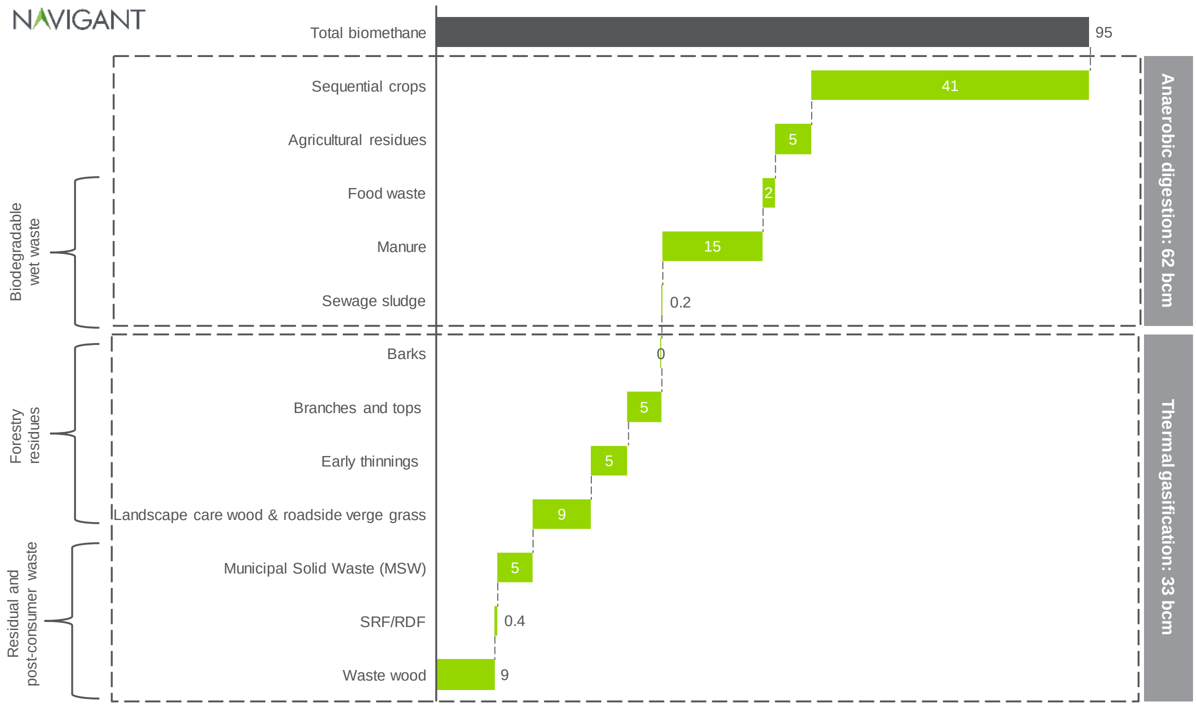
4 Global Syngas Technologies Council, "The Gasification Industry," https://www.globalsyngas.org/resources/the-gasification-industry.

5 Bioenergy International, "Göteborg Energi winds down GoBiGas 1 project in advance," 2018, https://bioenergyinternational.com/research-development/goteborg-energi-winds-gobigas-1-project-advance.

6 Chalmers University of Technology, 2018. GoBiGas demonstration – a vital step for a large-scale transition from fossil fuels to advanced biofuels and electro fuels. https://www.chalmers.se/SiteCollectionDocuments/SEE/News/Popularreport_GoBiGas_results_highres.pdf

7 The cost figures are slightly lower than what is reported in the cited reference because these costs are recalibrated using a social discount rate of 5%.

Figure 1. EU biomethane potential per conversion technology and feedstock (in bcm natural gas equivalent) type by 2050



Source: Gas for Climate 2019, analysis by Navigant.

Biomethane would be produced at many production sites across Europe. Large 200 MW_{th} gasification plants would be located at port locations with connections to existing gas grids. Woody biomass will be transported to these installations by ship. Over 200 of such installations could be in operation by 2050. Thousands of anaerobic digesters would be located throughout the European countryside, close to agricultural biomass. Agricultural biomass has a high moisture content that makes it costly to transport over long distances, meaning that anaerobic digesters would be relatively small in size. Today, the average European digester produces 290 m^3 of raw biogas per hour. In the future, the average biogas plant is expected to be larger to reduce capital costs, meaning that biomass would be sourced from multiple farms in the region. The average digester could have a size of 500 m^3/hr or even larger. In Denmark, much larger digesters of more than 2,000 m^3/hr are being constructed today. From a production cost perspective, it can be efficient to transport raw biogas from multiple neighbouring digesters via small pipes under low pressure to a central biomethane installation, where CO_2 is removed from raw biogas to create biomethane at natural gas quality, with a methane content of 97%. Alternatively, large integrated biogas and biomethane installations of 1,000 m^3/hr or more could be constructed within reach of gas grids.

Areas with a lot of animal husbandry can be interesting from a biomethane potential perspective, agricultural biomass is also available throughout the European countryside. Existing gas grids are particularly dense in some EU member states, while other countries have a more thinly spread gas pipeline network. It will not be possible to connect all the biomethane potential to gas grids. A certain share of digesters can be located far from existing gas grids and it would be costly to connect them to existing gas grids. Within the scope of the present study, no detailed analysis has been performed on this aspect; however, about two-thirds of the biomethane potential based on anaerobic digestion could find its way to Europe's gas grids. This estimation could benefit from further in-depth analysis.

The large biomethane scale-up potential as described in the 2019 Gas for Climate study will Such scale-up will only be possible if production costs decrease, climate benefits are maximised and a sustainable feedstock supply is ensured. Navigant's analysis shows that all biomethane can be zero emissions renewable gas by 2050, and any remaining life cycle emissions can be compensated by negative emissions created in agriculture on farms producing biomethane. It is important to properly map and mitigate methane leakage risks in biomethane production.

Biomethane has multiple benefits, including its ability to foster sustainable and more circular agriculture. One significant benefit of biomethane is its ability to generate negative emissions. Biomethane can be fed to blue hydrogen production facilities (steam methane reformers or autothermal reformers with CCS) to produce hydrogen and generate negative carbon emissions. To differentiate it from blue hydrogen that uses natural gas as feedstock, this hydrogen could be called climate positive hydrogen. The ability of biomethane to create negative emissions is significant because the most authoritative climate change scenarios show that the world needs significant negative emissions to keep global temperature increase well below 2°C.[8] Negative emissions are needed not just during the coming decades but will still be needed after 2050. In terms of the scale-up pathway for climate positive hydrogen, it can be assumed that biomethane production needs to be scaled up during the 2020s and 2030s to satisfy direct demand for biomethane such as for the heating of buildings. Depending on the extent to which valuable direct biomethane uses are supplied, and the willingness of society to pay for various options to create negative emissions, climate positive hydrogen can start to play a meaningful role during the 2040s and continue after 2050.

In addition to ensuring sustainable production and minimising life cycle emissions, another necessary enabler of biomethane scale-up is a reduction in production costs. The Gas for Climate 2019 study concluded that significant cost reductions are possible. Production costs in both production routes can decrease from the current €70–€90/MWh to €47–€57/MWh in 2050. It is possible to use biomethane production sites to produce also power to methane by methanation of CO_2 captured in biogas upgrading. The Gas for Climate 2019 potential showed a potential for this of about 150 TWh or 14 bcm natural gas equivalent, limited by the availability of cheap otherwise curtailed electricity to produce green hydrogen as feedstock. Even assuming cheap electricity as input, power to methane is a relatively expensive production route, yet it does enable a valorisation of otherwise emitted CO_2 at biogas plants.

8 Chapter 2 of the IPPC Special Report on Global Warming of 1.5° (2018), shows that significant negative emissions are require in most climate change mitigation scenarios to reach well below 2 degrees an 1.5 degrees. See: https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_Chapter2_Low_Res.pdf

1.2 Biomethane pathway under current EU climate and energy policies

Conclusion Current EU Trends

Current EU climate and energy policies can expect to drive an increase of biomethane production, especially in France, Italy, and Denmark where favourable biomethane support schemes exist. This could lead to a significant growth from the current 2 bcm of grid-injected biomethane to around 20 bcm by 2030. A continuation of today's climate ambition towards 2050 (as stipulated in the EU Climate and Energy Package for 2030) is unlikely though to result in 95 bcm of biomethane by 2050, especially because building over 200 large gasification plants would require large capital investments which could only be mobilised with long-term policy stability and significant subsidies. While biomethane costs will decrease under current policies, it is unlikely that the low production cost levels as specified in the Gas for Climate 2019 study could be achieved.

1.2.1 EU policies

This pathway assumes that the current EU Climate and Energy Package for 2030 is fully implemented. This study expects that a full implementation of 2030 climate and energy framework could result in an increase in biomethane production volumes to roughly 20 bcm by 2030, this represents 4% of the current natural gas demand in the EU.[9,10] Today, a quantity of 16 bcm of biogas is produced that is not upgraded to biomethane and injected to gas grids but is used locally to produce electricity and heat. Depending on how national subsidy schemes and mandates develop, it may be that an important part of this biogas production would be upgraded to biomethane. In addition, steady growth of new, larger integrated biogas-biomethane plants can be expected. On biogas to biomethane gasification, it is likely that the EU Innovation Fund will co-fund several large commercial-scale gasification projects before 2030. However, under current policies, no driver exists for the deployment of several dozens of those facilities, which cost several hundreds of million euros each.

Some of the key EU policies that could support this uptake of biomethane include the following:

- **Renewable Energy Directive:** The new Renewable Energy Directive (RED II) introduced a legally binding, EU-wide target of 32% renewable energy consumption by 2030 that includes specific targets for demand sectors. For the transport sector, RED II has a sub-target of 3.5% for advanced biofuels that would include biogas/biomethane produced through wastes and residues. The RED II has also capped the use of energy crops (only low indirect land-use change [ILUC] risk) to 2020 consumption levels, since the bulk of biofuels are currently produced through energy crops that are associated with sustainability concerns, including ILUC. The share of crop-based biofuels in each member state in 2020 will set the limit until 2030.[11] RED II promotes the use of sustainably sourced biomass for energy production and requires that biogas and biomethane must reach 65%-80% greenhouse gas savings depending upon the demand sector, when measured against their fossil fuel comparators. RED II also requires member states to extend existing guarantees of origin schemes to include renewable gases such as biomethane and hydrogen. This would facilitate greater cross-border trade of such gases between member states. Through these measures, there can be a reasonable demand for sustainably produced biomethane in the EU energy system from 2021 onwards.
- **Innovation Fund:** The Innovation Fund is one of the funding instruments under EU ETS that supports the European Commission's strategic vision for a climate-neutral Europe by 2050. The Innovation Fund was established for 2021-2030 and is endowed with at least 450 million allowances that can amount to around 10 billion euro depending on the carbon price. It focuses on the demonstration of the next generation low carbon technologies and processes needed for the EU low carbon transition. The Innovation Fund can create the right incentives for companies and public authorities to invest

9 Gross inland consumption of natural gas in the EU is around 18,100 PJ or 472 bcm in 2018, https://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_103m&lang=en.

10 This biomethane share is likely to originate from countries that are leading in biogas and/biomethane production and use. The countries that are expected to significantly contribute towards achieving these production volumes are France, Italy, Netherlands, Germany, and the UK. These countries are responsible for 69% of the total EU natural gas consumption in 2018, see Appendix B for Gross Inland Natural Gas Consumption per EU member state.

11 The support to biofuels with a high risk of ILUC will be frozen at 2019 levels until 2023 and phased out completely in 2030. Through the adoption of a delegated act in March 2019, palm oil diesel is considered a high ILUC risk and will not count towards EU renewable energy targets by 2030.

in the commercialisation and upscale of thermal gasification technologies as these projects face funding issues for continuous operation and development. As a predecessor of the Innovation Fund, EU's NER 300 initiative funded Verbio's new technology, which uses 100% straw for biomethane production.[12]

With the transposition of EU legislation at a national level, we expect more countries to introduce specific targets on biomethane production and use (like France and Italy, see Section 1.2.2). These policies are likely to introduce a shift from electricity towards gas production, enabling the conversion of many existing biogas plants that are used for electricity to biomethane that can be injected into gas grids. With countries that lack similar support, the intrinsic value of biomethane could be realised in a free market. Organising a market of tradable biomethane certificates backed by guarantees of origin is a practical possibility for monetising the intrinsic value of biomethane. National legislation combined with growing market for certificates could establish a meaningful position of biomethane in the EU energy system.

1.2.2 Regional differences today

Many EU member states have already implemented policies supporting the production and use of biomethane. These policies encourage the deployment of biogas and biomethane plants and are expected to enable continued growth.

The number of biogas plants increased considerably. Germany has been the driving force for biogas development for many years and has the largest number of operational biogas plants (10,971), followed by Italy (1,655). France, Switzerland, the UK, and Czech Republic follow their lead with more than 500 plants each.

The number of biomethane plants increased from 187 plants in 2011 to around 550 plants in 2017. Germany had the highest number of biomethane plants (208)[13], followed by the UK (92) and Sweden (70). In 2017, however, the number of biomethane plants had the fastest growth in France (+18),[14] thanks to the introduction of favourable incentive schemes and renewable gas targets. France is followed by the Netherlands (+13) and Denmark (+8). Since 2019, Italy has seen a boost in new biomethane investments, with about 40 new plants expected to become operational during 2020.

Some of the EU countries that lead biogas and biomethane production and have introduced policies encouraging its uptake and use as shown in the following table.

12 Verbio press release, "New Verbio Plant for the Production of Biomethane from 100 Percent Straw Commissioned as Scheduled," 15 April, 2015, https://www.verbio.de/en/investor-relations/news-publications/press-releases/new-verbio-plant-for-the-production-of-biomethane-from-100-percent-straw/.

13 https://www.dena.de/fileadmin/dena/Dokumente/Veranstaltungen/EBC_2018/Praesentationen/11_Matthias_Edel_dena.pdf

14 The number of biomethane plants in France increased by 73% in 2018 to reach a total of 76 units, https://www.biogasworld.com/news/biogas-biomethane-market-france/.

Table 1. Member state biomethane policies

Germany	France	Italy
Although still a leader in biogas and biomethane production, the 2014 amendments to the Renewable Energy Act cancelled specific biogas-related targets for 2020 and 2030. These amendments led to a slowdown in the construction of new biogas plants in Germany. Grid access regulation obliges biogas to be upgraded to natural gas quality for injection into the gas grid. The grid operator is responsible for adjusting the green gas characteristics to local grid conditions. By the end of 2017, 208 plants were producing 9.8 TWh of biomethane injected to the grid.	The Energy Transition Law of 2015 set a target of 10% biomethane coverage in annual average gas consumption by 2030. This target was set with a view to limit global warming to 2°C by 2050. However, to meet the 1.5°C target, the rate of renewable gas development needs to be accelerated. Engie wants to bring this target up to 100% by 2050, by adding other low carbon gases to the mix, such as hydrogen. In 2017, 18 more plants came online to reach a total of 44 plants. By the end of 2019, there are 123 plants operational in France accounting for 2.2 TWh/year of capacity. 1,085 plants are under development for a total biomethane capacity of 24 TWh/year.	In the beginning of 2018, the government published a decree that gives subsidies only in case of biomethane use as a transport fuel. The new decree has an approximate budget of €4.7 billion and is intended for plants beginning operations between 2018 and 2022 up to a total of 1.1 bcm per year. Most of the biogas facilities now producing electricity are likely to be upgraded to biomethane because of the decrease in subsidies for electricity production. By the end of 2017, there were 1,655 biogas plants and one biomethane plant operational in Italy. By 2020 the number of biomethane plants will have increased to 40.

Source: [15, 16, 17, 18]

1.2.3 Biomethane technology and price developments

For anaerobic digestion, there is a trend towards increased biogas digester size. Currently, the EU average stands at 0.59 MWe or 290 Nm^3/hr.[19] Some countries have higher digester sizes installed. For example, the average biogas digester size is 2.68 MWe (1,300 Nm^3/hr) in the UK, followed by Ireland with an average digester size of 1.79 MWe (870 Nm^3/hr). Plants smaller than the European average can be found in Germany, Austria, Switzerland, Denmark, and Estonia.[20] The European average is expected to increase, which would result in cost reductions through economies of scale. The average costs from feedstocks will drop slightly as the share of energy crops will reduce, while costs of agricultural residues increase towards 2030. Under this scenario, the costs of biomethane are expected to remain slightly higher than the levels estimated in Gas for Climate for 2050. This is because the benefits from sequential cropping will not be fully tapped as the current EU 2030 package does not facilitate the testing and scale-up of cover crops in regions of Europe that are climatologically suitable for its application. This will impact feedstock costs and limit the possibilities of pooling of biomass resources to enable the installation of bigger facilities.

For thermal gasification, first of a kind plants can be funded through the EU ETS Innovation Fund or through any unspent funds from the now terminated EU NER 300 subsidy programme. Countries like the Netherlands, Austria, the UK, and France have already built pilot scale plants and could be a front-runner in installation of first commercial-scale facilities. The plant construction and commissioning can take up to 4 years, which means that by 2025 there can be several commercial-scale facilities running across Europe. Continued deployment under current policies could lead to the construction of relatively large-scale standalone plants (Nth of a kind [NOAK]) with a production capacity of around 50 MW$_{th}$ by 2030. Costs for such commercial-scale facilities could come close to €80/MWh. The deployment would continue post-2030 resulting in further cost benefits from economies of scale and efficiency improvements. By 2050, the costs from (thermal) gasification will reach the Gas for Climate levels of €47/MWh under this scenario.

15 Green Gas Initiative, Biomethane – Naturally Green Gas, 2017, https://www.greengasinitiative.eu/upload/contenu/ggi-biomethane_report_062017_1.pdf.

16 GRTgaz, Renewable Gas French Panorama, 2017, http://www.grtgaz.com/fileadmin/plaquettes/en/2018/Overview-Renewable-Gas-2017.pdf.

17 EURACTIV, "Europeans confront biomethane cost reduction challenge," 2019, https://www.euractiv.com/section/energy/news/europeans-confront-biomethane-cost-reduction-challenge/.

18 CIB, The biogas and biomethane market in Italy, 2018, https://www.gas-for-energy.com/fileadmin/G4E/pdf_Datein/g4e_2_18/02_fb_Maggione.pdf.

19 EBA Annual Report 2019. https://www.europeanbiogas.eu/wp-content/uploads/2020/01/EBA-AR-2019-digital-version.pdf

20 EBA Annual Report 2019. https://www.europeanbiogas.eu/wp-content/uploads/2020/01/EBA-AR-2019-digital-version.pdf

1.2.4 Pathway towards 2050

Presuming that current EU climate and energy ambition levels would continue up to 2050 it can be assumed that a moderate growth in biomethane will continue. This will most likely result in the mobilisation of far less than full EU biomethane potential by mid-century.

Especially anaerobic digestion from biomass cultivated through sequential cropping will not significantly grow without dedicated piloting, training, and awareness raising campaigns. Also, capital-intensive investments in biomass-to-biomethane gasification units are unlikely to scale-up to enable 200 large 200 MW gasification plants to be built.

As a consequence, the EU would inevitably continue to rely on natural gas even though volumes may decrease somewhat. The target of achieving a net-zero emissions EU energy system by mid-century would not be achieved.

1.3 Accelerated Decarbonisation Pathway – biomethane

Conclusion Accelerated Decarbonisation

The Accelerated Decarbonisation Pathway envisions that EU countries will implement higher targets on the production and use of biomethane as part of the EU Green Deal. There would be regional variation in targets and measures due to different gas supply demand characteristics per country, availability of feedstock resources, and existing infrastructure. Biomethane production could reach 10% of total EU gas consumption by 2030, or around 370 TWh, 35 bcm natural gas equivalent. In this scenario, a large uptake of sequential cropping could enable an accelerated biomethane production up to the level of 95 bcm as estimated in the Gas for Climate 2019 study. Significant biomethane production cost reductions can be expected.

1.3.1 The European Green Deal and related developments

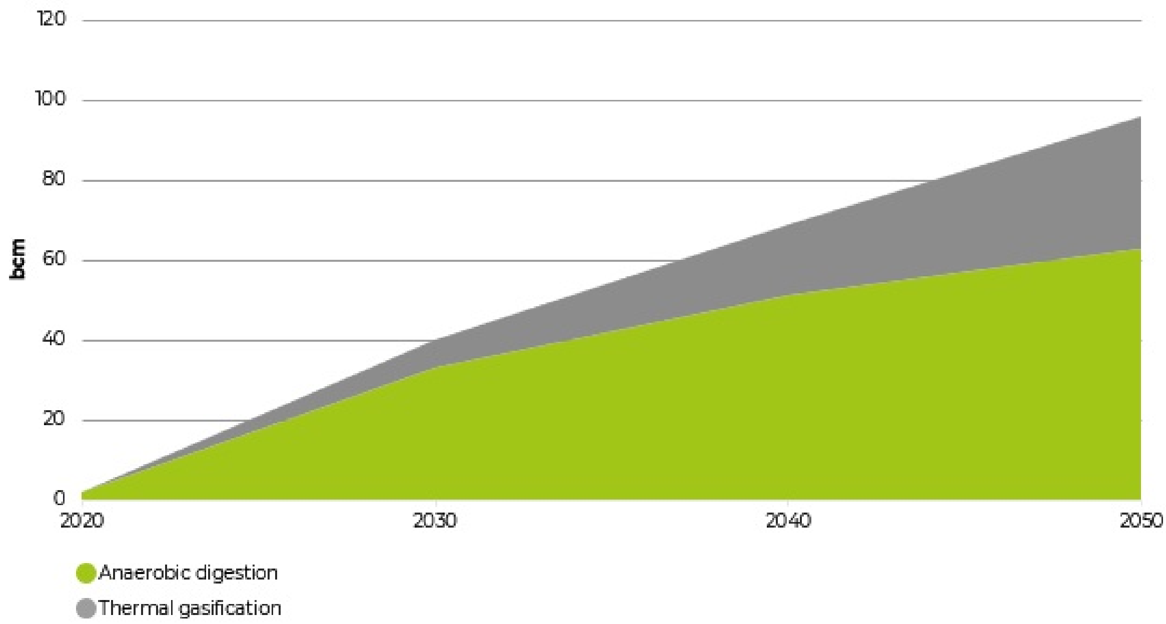
The Accelerated Decarbonisation Pathway envisions a higher ambition level in climate and energy policy and a greater overall societal momentum to combat climate change. The Green Deal will revise the emission reduction target of 40% to a more ambitious 55% by 2030.[21] This will probably lead to a more ambitious EU RED and EU ETS, which is likely to improve the relative business case of biomethane. In this context, biomethane from anaerobic digestion, can be scaled up much more rapidly. Also, it increases the likelihood that large investments in large biomass-to-biomethane gasification plants can be mobilised. This could lead to a situation in which the Accelerated Decarbonisation Pathway could generate 370 TWh or 35 bcm natural gas equivalent of biomethane per year by 2030 through:

- Converting 12 bcm of biogas that is already produced today for local electricity and heat towards grid-injected biomethane.
- Constructing 6,000 new digesters, each with an average production of 500 m^3/h and 3,000 new centralised biogas upgrading units that will each convert biogas from two digesters to biomethane. All these installations in total produce 15 bcm of biomethane.
- Constructing 500 new integrated biogas-biomethane plants that each produce 2,000 m^3/h biogas into biomethane and jointly produce 5 bcm of biomethane.
- Getting 2,000 farmers and biogas producers, mainly in Italy and France, to adopt Biogasdoneright.[22]
- Constructing 21 large 200 MW gasification plants that jointly produce 3 bcm of biomethane.

21 The European Commission, "The European Green Deal," 2019, https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

22 Biogasdoneright is an innovative concept of sustainable farming and biogas production developed in Italy that was described in more detail in the Gas for Climate 2050 study published in 2019. It applies sequential cropping meaning that two crops are cultivated on a plot in constant rotation during the year. This increases the agricultural productivity of existing farmland without negative environmental impacts and without direct or indirect land use change. Biogasdoneright leads to co-benefits such as decreasing soil erosion risks, an increase in on-farm biodiversity and a potential increase of the soil carbon content by leaving more agricultural residues on the land.

Figure 2. Accelerated Decarbonisation Pathway



Source: Guidehouse

Such scale-up of biomethane production will be possible only if:

1. It becomes easier to market and trade biomethane across borders
2. The European Union and EU member states (continue to) support a scale-up of biomethane while driving a constant reduction of production costs
3. A large programme of Biogasdoneright piloting, training, and awareness building takes place

Increased cross-border trade and transport

Today it is not straightforward to trade biomethane between countries within the EU internal market. Even though a CEN standard exists for blending biomethane in natural gas, EU member states have different standards for gas quality. Also, there is a lack of international arrangements that acknowledge national guarantees of origin for biomethane in case of cross-border trading. These barriers could be lifted by the creation of an EU-wide system of Guarantees of Origin for renewable gas, combined with certificates that demonstrate compliance with EU sustainability criteria for biomethane. In addition to this, a greater degree of harmonisation of gas quality should be explored, including clarify on who is responsible to manage (cross-border) gas quality.

Policy support driving a scale-up at reduced production costs

Biomethane production costs today are more than double the price of natural gas plus the CO_2 price. Government support is needed to increase biomethane production, while production cost reductions are needed to ensure longer-term political support. Cost reductions can be achieved through economies of scale, rationalisation of anaerobic digestion supply chains, and technological progress:

- Biogas producers should invest in larger biogas digesters. Today, the average digester in Europe has a raw biogas production capacity of 290 Nm^3/hr. It would be feasible and cost-efficient to increase the capacity of new digesters to at least 500 Nm^3/hr, preferably even larger. National policy incentives can steer this development. Famers should increasingly pool biomass resources into larger digesters.
- Biomethane producers, energy companies and investors should invest in large biogas to biomethane upgrading facilities, either large integrated facilities or large installations that pool biogas from various smaller biogas installations.
- Large energy companies should start investing in commercial-scale biomass gasification plants, each requiring several hundreds of million euros. The EU Innovation Fund offers a potential source of funding for these projects.

- Technology providers need to continue to maximise digester and gasifier efficiencies, both through technological improvements and through improved bacterial processes.

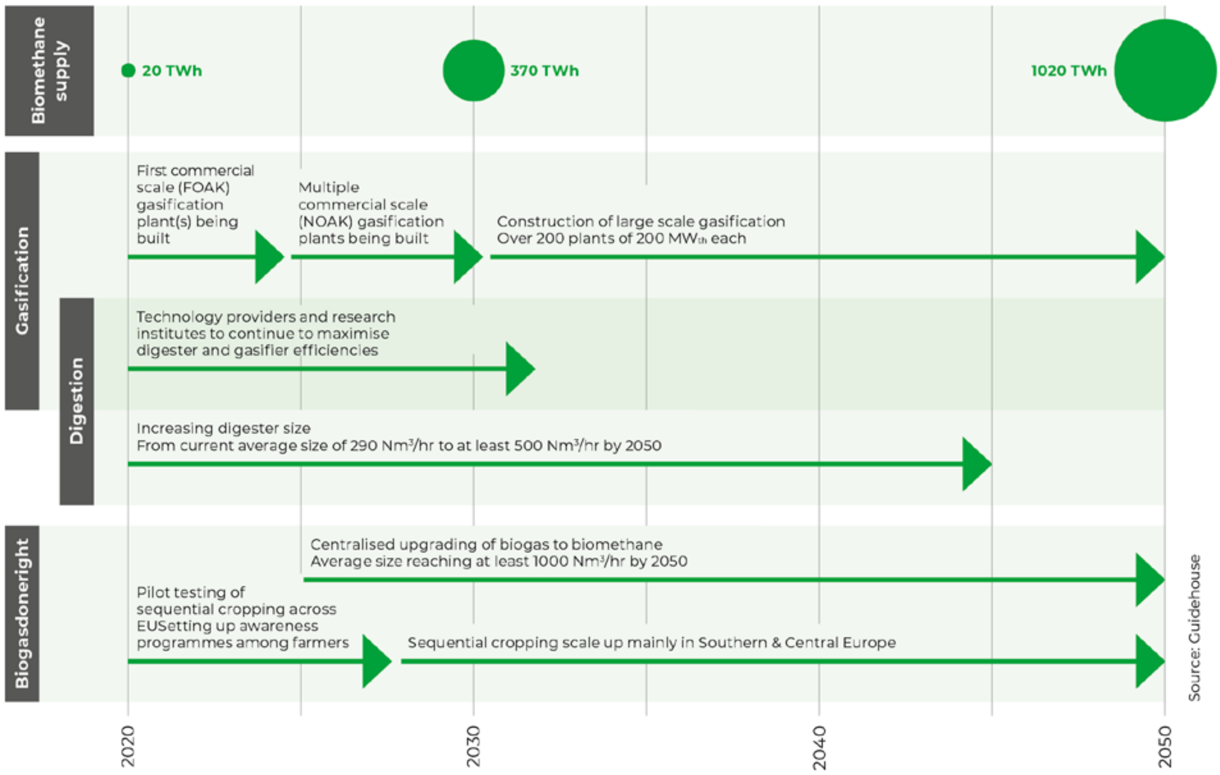
Increased deployment of Biogasdoneright

Today, the concept of Biogasdoneright is applied by about 1,000 farmers in Italy and a few hundred in France. Research is needed to test to what extent the concept can be implemented in more temperate parts of Europe as well. Large-scale training and awareness raising programmes would need to be implemented among farmers in all countries in which sequential cropping, organic fertilisation, precision, and conservation farming is demonstrated to be a promising concept.

Post-2030, a continuation of the policy and societal drivers will continue to accelerate biomethane deployment during the period 2030 to 2050. In this scenario, it would be likely that the full EU biomethane potential of 95 bcm natural gas equivalent can be mobilised by mid-century.

In addition to this, about 14 bcm natural gas equivalent of power to methane could be produced using already captured CO_2 from biogas to biomethane upgrading at rural biomethane plants combined with locally produced green hydrogen using cheap excess electricity.[23]

Figure 3. Critical timeline biomethane supply



23 In the Accelerated Decarbonisation Pathway, about 250 TWh of excess electricity would be available by 2050 to produce around 200 TWh of green hydrogen. To produce power to methane with the same amount of hydrogen, 33 million tonnes of carbon dioxide is required, which requires, in turn, a production of 43 bcm of raw biogas with a CO_2 content of 45% and methane content of 55%. Assuming a methanation reaction efficiency of 80%, this results in total EU-wide production of 147 TWh (HHV) of renewable methane from power to methane.

Box 1: Biogasdoneright and the circularity of carbon

A large part of the EU biomethane potential of 95 bcm as analysed in the 2019 Gas for Climate study is based on biomass from sequential cropping. This is a form of agricultural crop production in which two instead of one crop are produced on a to generate additional, low ILUC risk biomass. The 2019 Gas for Climate study assumes that by 2050 ten percent of the EU agricultural area would apply sequential cropping, with a focus on warmer areas in the south and a more limited potential in the temperate and cooler northern climate.

Navigant's optimism about the potential for sequential cropping is based on a promising concept developed by farmers and biogas producers in Italy called Biogasdoneright. The concept is a departure from a traditional way of farming towards more innovative and sustainable farming practices. It increases the agricultural productivity of existing farmland without negative environmental impacts and without direct or indirect land use change. Biogasdoneright leads to co-benefits such as decreasing soil erosion risks, an increase in on-farm biodiversity and a potential increase of the soil carbon content by leaving more agricultural residues on the land and through the application of digestate. It could also result in negative carbon emissions. Navigant assessed the environmental sustainability of Biogasdoneright in Italy together with experts from Wageningen University during 2016 and could verify the concepts sustainability claims. Navigant did not yet evaluate the soil carbon accumulation as this would require multi-year carbon budget assessments.

The production of biomethane using the principles of Biogasdoneright enables the capture of additional carbon via photosynthesis for the purposes of energy. This agricultural intensification results in additional carbon being sequestered in soil via agroecological practices. High CO_2 content in the soil causes soil fertility to enhance thereby offering a cheap and sustainable way to remove CO_2 out of the atmosphere. The carbon that was once released from underground fossils returns to the ground – making it a closed carbon cycle.

1.3.2 Technology and price development for biomethane

Access to additional biomass and trained farmers enable improved biomass sourcing strategies through local and regional collaboration, making it possible to pool biomass feedstocks and move towards increased digester sizes to benefit from economies of scale. The expected cost reductions from feedstock, increased biogas yields, economies of scale (digester and upgrading), valorisation of digestate, and longer plant lifetimes would result in production cost levels of €57/MWh by 2050. These estimates depict around 30% cost reductions from today's levels.[24] Thermal gasification would also experience increased deployment, starting with first commercial-scale projects and later NOAK large-scale facilities with sizes reaching 100 MWh. The costs for such commercial-scale facilities could drop to €70/MWh by 2030. Countries with high volumes of municipal and industrial solid waste, forestry residues, and port locations can attract larger facilities, enabling considerable upscale of thermal gasification. The accelerated deployment would continue post-2030 resulting in further cost benefits from economies of scale and efficiency improvements. The costs from thermal gasification will reach the Gas for Climate levels of €47/MWh well before 2050 under the Accelerated Decarbonisation Pathway.

1.4 Global Climate Action Pathway – biomethane

Conclusion Global Climate Action

24 The estimated cost reductions (€94/MWh to €66/MWh) for a French industrial facility in the short to mid-term are around 30%, see page 6. http://www.enea-consulting.com/wp-content/uploads/2018/10/ENEA_Feuille_de_route_biom%C3%A9thane.pdf.

Although the Gas for Climate 2050 Optimised Gas end state can be reached under the Accelerated Decarbonisation Pathway, biomethane developments can be further accelerated with breakthrough technologies and their widespread adoption in other parts of the world. Additional biomethane volumes would be available to the EU due to imports coming from Belarus, Ukraine, and Russia. Thermal gasification could be increasingly integrated with CCS (BECCS) to create negative emissions.

This pathway assumes that a global effort similar to what is envisioned in the European Green Deal will lead to new technological and commercial breakthroughs. The developments in the Global Climate Action Pathway are technology driven and are an addition to the Accelerated Decarbonisation Pathway.

Similar developments worldwide would mean that sequential cropping is also widely applied in other parts of the world. Since there are large quantities of agricultural land in Ukraine, Belarus, and Russia, these countries might produce considerable amounts of surplus biomethane that could be easily imported in the EU through the existing natural gas infrastructure.

1.4.1 Expected technology and price development

There is a possibility for further technological learning effects resulting from a greater global deployment of biomethane production technologies. This could result in additional production cost reductions. Navigant does expect the largest additional cost reductions to be possible for large-scale and CAPEX-heavy gasification technologies. Moreover, thermal gasification might experience additional avoided emission benefits through the integration of CCS. The application of CCS would result in additional costs but will increase the technology's net benefits since negative emissions are generated in the energy system. [25]

25 Ecofys & E4tech, 2018. Innovation Needs Assessment for Biomass Heat. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699669/BE2_Innovation_Needs_Final_report_Jan18.pdf

2. Hydrogen Deployment Pathways

Key Takeaways

- Current EU climate and energy policies are insufficient to unlock the potential for sustainable hydrogen production in the EU. They do not create the boundary conditions for rapid green hydrogen upscaling. As a result, it would be challenging to reach the supply volumes required by 2050, as found in our Gas for Climate 2019 report.

- Additional climate and energy policies in the framework of the EU Green Deal could drive up supply of green hydrogen to 50 TWh by 2030, while blue hydrogen would be scaled up more rapidly as well. In the early 2040s, cheap green hydrogen would surpass the production of blue hydrogen. Volumes described in the Gas for Climate 2050 Optimised Gas Scenario would likely be reached, arriving at 2,270 TWh by 2050, including demand for aviation fuels and petrochemicals

- Technological breakthroughs could significantly reduce the domestic production costs of blue and especially green hydrogen. These lower costs could create additional demand and supply for hydrogen-based solutions. However, imports of hydrogen-based fuels and feedstocks, like synthetic kerosene and methanol, would reduce the direct demand for hydrogen in the EU to 1,650 TWh by 2050. Furthermore, imports of green hydrogen from North Africa by upgrading existing gas import pipelines may enter the picture, and possibly blue hydrogen imports from regions with large gas reserves like Russia may start playing a role as well.

2.1 Introduction

Hydrogen is widely regarded as an energy carrier that will be crucial to coupling the electricity and gas sector via the existing infrastructure, thus cost-effectively decarbonising the EU's economy. Besides being an important chemical feedstock, hydrogen will also find end uses in high temperature heat for industry as a transport fuel and as an energy storage medium, e.g. for the electricity system. Today, the dominant hydrogen production routes in the EU continue to be steam methane reforming of natural gas and, to a lesser extent, the recovery of by-product hydrogen from the (petro)chemical industry. For hydrogen to fulfil its role as a versatile low carbon energy carrier, conventional hydrogen plants will need to implement carbon capture and renewable hydrogen production will need to be scaled up significantly.

This study distinguishes between several types of hydrogen, grouped by greenhouse gas emissions from the production process of the gas (hydrogen itself causes no greenhouse gas emissions at point of use):

- Grey hydrogen is gas produced by thermochemical conversion (such as steam methane reforming) of fossil fuels without carbon capture.
- Blue hydrogen is a low carbon gas produced by thermochemical conversion of fossil fuels with added CCS.[26]
- Green hydrogen is a renewable gas produced from renewable electricity sources such as solar PV and wind. In this study, the focus is on electrolysis (i.e. electrolytical hydrogen; see below), although other production methods are available too.[27,28]

Also, this study introduces the concept of 'climate positive hydrogen', meaning hydrogen produced from biomethane in blue hydrogen production installations and creating negative emissions.

2.1.1 Current situation

According to the Hydrogen Roadmap Europe, the current use of hydrogen in the EU amounts to 339 TWh.[29] The EU produces grey hydrogen; there is no production of green (except in smaller pilot plants) and blue hydrogen. Around 90% of the hydrogen used in the EU today is produced in a captive process,[30] meaning that natural gas is supplied to a site where the hydrogen is produced and used, mostly in refineries, ammonia plants, or methanol plants. Plans are under development in the Netherlands, the UK, and Germany plan to retrofit steam methane reformers with CCS or to develop new autothermal reformers with CCS. Costs for grey hydrogen production through steam methane reforming are around €1/kg, or €28/MWh, whereas blue hydrogen could be between €37-€41/MWh, depending on the technology.[31] Alkaline electrolysers are currently the most mature green hydrogen production technology, with conversion efficiencies of around 65-70% on Lower Heating Value (LHV) basis. Costs for electrolysis are estimated at around €70-100/MWh.[32]

2.1.2 Gas for Climate 2050 Optimised Gas end state

In the Gas for Climate 2050 Optimised Gas end state, about 200 TWh of green hydrogen from curtailed electricity could be supplied for an average cost of €29/MWh and more than 2,000 TWh of green hydrogen from dedicated renewable electricity generation could be supplied for €52/MWh. At that cost, the total demand in buildings, industry, transport, and power generation amounts to 1,710 TWh of hydrogen. In addition, there is a significant demand for hydrogen to produce synthetic fuels in the pathway, to decarbonise the aviation sector (380 TWh of hydrogen) and for petrochemicals (180 TWh of hydrogen). These are added to the total additional demand for hydrogen, arriving at 2,270 TWh. Although this shows that all the demand could potentially be met with green hydrogen by 2050, an important role is recognised for blue hydrogen in the

26 Other options, most notably carbon capture and utilisation (e.g. via methane cracking and methane pyrolysis) need to be further technically developed and evaluated for their real greenhouse gas emission reduction potential (i.e. long-term carbon sequestration potential).

27 For instance, direct photochemical conversion, supercritical wet biomass conversion, biomass gasification, fermentation, but also the use of biogas in steam methane reformers, with or without CCS.

28 Further specifications (e.g. specific greenhouse gas intensity limits in green / blue hydrogen production) on these definitions will be available at the conclusion of the design phase for the green hydrogen Guarantees of Origin at CertifHy (http://www.certifhy.eu/).

29 Fuel Cells and Hydrogen Joint Undertaking, 2019, *Hydrogen Roadmap Europe.* Available at: https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf.

30 Roads2HyCom, 2007. Industrial surplus hydrogen and markets and production, http://citeseerx.ist.psu.edu/viewdoc/summary?doi=10.1.1.477.3069

31 Prices based on natural gas price around of €15/MWh, which is the average price of European gas future contracts at the time of writing. Prices for grey and blue hydrogen can be higher or lower depending on the gas price.

32 Range based on hydrogen cost analysis performed in this study. For more details, see Appendix 2. The range is mainly explained by differences in electrolyser CAPEX, cost of electricity and full load hours.

period up to 2050. Blue hydrogen can scale-up rapidly, independent of the availability of low-cost renewable power, which is the main limitation to scaling up green hydrogen. Boundary conditions for blue hydrogen are CO_2 transport infrastructure and enough permitted CO_2 injection and storage sites. For this reason, scaling up blue hydrogen in the short term while developing green hydrogen supply in parallel can accelerate decarbonisation compared to a situation where blue hydrogen would not be allowed to play a role. The Gas for Climate 2019 study sees a large potential for retrofits of conventional hydrogen assets with CCS, which could kick-start the use of low carbon hydrogen. After 2050, part of the blue hydrogen production infrastructure can continue to be used to produce climate positive hydrogen using biomethane as input for blue hydrogen plus generating much-needed negative emissions

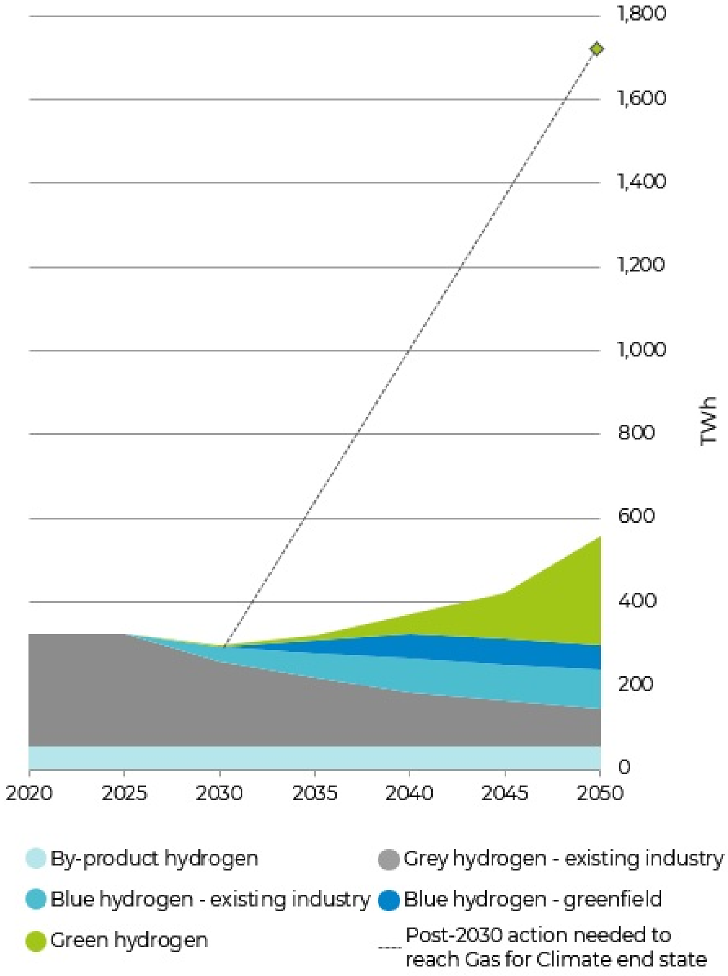
The current analysis explores various pathways to scale-up hydrogen to achieve full decarbonisation of the EU economy in a cost-optimal way, as described in the Gas for Climate 2050 study. This chapter focuses on near- and mid-term developments of green and blue hydrogen while assessing the likelihood and possible scale of imports from outside the EU.

2.2 Hydrogen pathway under current EU climate and energy policies

Conclusion Current EU Trends

Under current EU policies, it is likely that part of existing hydrogen production will be retrofitted with CCS by 2040. The effect of this in the pathway amounts to a supply of around 40 TWh blue hydrogen by 2030 and 140 TWh by 2040. Support mechanisms such as the Innovation Fund are expected to finance projects that retrofit conventional hydrogen units in refineries, industrial gas producers and the ammonia and methanol industry. This pathway sees the development of new blue hydrogen projects stagnating after 2040 as a result of society and policymakers viewing CCS as a transition option, which limits the development of greenfield blue hydrogen plants with a lifetime reaching far beyond 2050. Support mechanisms and concrete targets for the supply of green hydrogen are largely absent in the EU at the moment, apart from the Netherlands, Belgium, and France. Announced plans for electrolysis in the EU will increase supply to around 4 TWh (2 GW) of green hydrogen by 2030, with this analysis estimating that still only around 260 TWh would be produced in 2050. Based on existing policy, we expect that both in the short- and long-term low carbon hydrogen production in the EU would remain limited, with a level of renewable and low carbon hydrogen production just above the current level of conventional hydrogen production in the EU. Additional policies will be needed in in 2020-2030 to reach an Optimised Gas end state in the EU energy system, estimated in the Gas for Climate 2019 report to require 1,710 TWh of hydrogen.

Figure 4. Current EU Trends Pathway for hydrogen deployment towards 2050



Source: Guidehouse

2.2.1 EU Policies

This pathway assumes that the current EU 2030 Climate and Energy package is fully implemented. The European Commission study, *A Clean Planet for All*[33], assumes in all its scenarios that developments are fixed until 2030, as most of the large policy files had already been finalised for this period and budgets are allocated. Consequently, the study assumes that only 2 GW of green hydrogen capacity will be installed by 2030, which could produce around 4 TWh.[34] In addition, we assume that in the short term, EU policies could stimulate 37 TWh of blue hydrogen projects in existing industries like ammonia, methanol, and petrochemicals. This blue hydrogen would replace existing demand for grey hydrogen and would therefore not contribute to satisfying new hydrogen demand in other sectors, like transport or power. Such a level of blue hydrogen deployment is comparable in scale to the Porthos and H-Vision projects in the Netherlands added together. EU-wide support mechanisms that can contribute to achieving this 2 GW of installed electrolyser capacity and 37 TWh of blue hydrogen production include the following:

- **Fuel Cells and Hydrogen Joint Undertaking**: A public-private partnership focusing on the commercialisation of fuel cell and hydrogen technology. Since its inception, it has provided €418 million to projects related to green hydrogen production, distribution, and storage.[35]

33 European Commission, In-depth analysis in support of the commission communication, COM(2018) 773. See: https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

34 Assuming an electrolyser efficiency of 65% and 3,000 full load hours.

35 Fuel Cells and Hydrogen Joint Undertaking (2019). *FCH-JU presentation to the Hydrogen Energy Network (HyENet),* https://ec.europa.eu/energy/sites/ener/files/documents/3-0_fchju_biebuyck.pdf

- **Innovation Fund**: The Innovation Fund is an initiative embedded in the EU ETS aimed at stimulating the deployment of innovative low carbon technologies in EU industry. The fund is endowed with 450 million EU emission allowances (EUA), representing a value of over €11 billion at an EUA price of €25. Large-scale production of hydrogen for energy storage will be funded under this support mechanism, as well as the decarbonisation of conventional hydrogen plants through CCS and the conversion of industrial processes to hydrogen technology. By converting industries to use more hydrogen, demand will also be stimulated, leading to a larger supply of potentially both green and blue hydrogen.
- **Important Projects of Common European Interest**: Achieving an IPCEI status can relieve major projects from state aid limitations. In December 2019, this was achieved for a seven-country battery value chain project. Under coordination by Hydrogen Europe, a cluster of international hydrogen projects is aiming for the same, under the name of Hydrogen for Climate Action.[36]
- **Renewable Energy Directive:** Although not directly stimulating the production of green hydrogen, RED II stipulates that member states need to extend existing Guarantees of Origin schemes to include renewable gases. This puts a value on green hydrogen produced from renewable electricity compared to hydrogen produced from natural gas and can stimulate market development. However, green hydrogen does have a competitive disadvantage in the RED because renewable electricity and advanced biofuels are eligible for multiple counting towards the renewable energy targets.

2.2.2 Regional differences

Besides these EU schemes, only a few member states have proposed or introduced targets or support mechanisms for green or blue hydrogen production. Namely:

- **Belgium**, **Flemish Hydrogen Roadmap:** A government-approved hydrogen roadmap in 2018, with specific targets set for 2030 and 2050 and an associated €50 million regional investment plan for power-to-gas. The roadmap foresees a potential of 1 TWh and 14 TWh in 2030 and 2050, respectively.[37]
- **France**, **Hydrogen Deployment Plan:** France allocated €100 million for funding and set 2023 and 2028 targets for low carbon hydrogen in industry, transport, and renewable energy storage. The targets include 20%-40% low carbon hydrogen use in industrial applications of hydrogen and a reduction in electrolysis cost to €2/kg-€3/kg (60 to 90 €/MWh) by 2028. Targets are also defined in the energy planning regulation for power-to-gas pilot development up to 10 MW by 2023 and 100 MW by 2028.
- **Netherlands:** In February 2020, the Dutch government published a subsidy mechanism (SDE++) to stimulate industrial decarbonisation. This mechanism will also cover the production of green hydrogen. The goal of the SDE++ is to reduce CO_2 emissions at the lowest costs. For green hydrogen, the most cost-effective subsidy amount is reached at 2,000 full load hours, which government estimates will give the lowest electricity costs and highest CO_2-reduction. However, capping the subsidy at 2,000 full load hours means that the capital costs of the electrolyser are relatively high, resulting in a high “basisbedrag” (base amount), meaning the production cost under which it would be eligible for a grant. As the goal of the SDE++ mechanism is to realise CO_2 reduction at the lowest costs, concern is that hydrogen will not receive the subsidies it needs to take off rapidly.[38]

Germany is expected to publish its national hydrogen strategy in the first half of 2020.

2.2.3 Technological and cost developments

Central questions to the development of green and blue hydrogen in the pathway are how competitive they are against each other in cost, and whether the boundary conditions are in place to allow for the rapid upscaling of green hydrogen.

The cost of green hydrogen production is sensitive to the electrolyser plant capital investment costs, electrolyser efficiency, electricity price, and the full load hours (capacity factor) at which the electrolyser can be operated. Alkaline electrolysers, currently the most mature electrochemical hydrogen production technology, are mainly used in the chlorine industry, but so far had few applications in electrolysis of water. Therefore, high costs were seen in the few projects that were done, with system costs of €1,000/kW or more. In the Gas for Climate 2019 study, we assumed a cost trajectory from that starting point. However, in the 12 months since its publication, we have seen rapid reductions in estimates for capital costs: according to the International Energy Agency (IEA) (2019), the lowest CAPEX today start at 450 €/kW_e[39], and Bloomberg NEF reported a

36 Hydrogen4ClimateAction (2019), *What's an IPCEI*, https://www.hydrogen4climateaction.eu/whats-an-ipcei

37 Waterstofnet & Hinicio (2018), *Het potentieel voor groene waterstof in Vlaanderen,* https://www.energiesparen.be/sites/default/files/atoms/files/Rapport-Vlaams-potentieel-groene-waterstof.pdf

38 Dutch Government (2019), *Beantwoording kamervragen over groene waterstof in SDE++,* https://www.rijksoverheid.nl/documenten/kamerstukken/2019/09/25/beantwoording-kamervragen-over-groene-waterstof-in-de-sde

39 IEA (2019), *The future of hydrogen*

2019 cost level of €1,100/kW for outside of China, but only €180/kW in China[40]. For consistency with the Gas for Climate 2019 report, we kept its electrolyser cost trajectory in the EU Current Trends and Accelerated Decarbonisation Pathways but explored much lower trajectories in the Global Climate Action Pathway, and in Chapter 5 (What if the future develops differently) of the core report.

Current alkaline electrolyser efficiencies are around 65%-70% and might increase further, although attaining efficiencies above 80% would likely require the introduction of proton exchange membrane electrolysers. However, such technological developments alone will not be responsible for significantly reducing production costs and making green hydrogen competitive with natural gas-based hydrogen from SMR or autothermal reformers (ATR) with CCS. Power costs need to come down significantly as well, with sufficient full load hours for the electrolyser. With the low natural gas prices of around €15/MWh that are seen today, hydrogen production with SMR and CCS would cost around €41/MWh versus €37/MWh for new build ATR.[41] In absence of policies that aim at bringing down the cost of green hydrogen, such as governments providing a grid connection to offshore wind parks and reducing the risk of financing electrolyser projects, it may not be cost-competitive with blue hydrogen before 2050.

2.2.4 Societal acceptance

In the EU, most member states have favourable or neutral attitudes towards CCS in their long-term climate strategies.[42] At the same time, in transposing the EU CCS Directive, some countries have introduced various limitations on the use of their CO_2 storage potentials.[43] In countries where CCS is embraced as an emissions abatement technology, the general understanding is that it should be used as a transition option until a fully renewable solution is available. This is expected to discourage investments in greenfield blue hydrogen plants that might have a lifetime beyond 2050. Therefore, on the longer term, additional hydrogen demand from end-use sectors is satisfied mostly with green hydrogen, in the Current EU Trends Pathway. Greenfield projects to produce blue hydrogen are needed to satisfy demand for low carbon hydrogen until 2040, but production levels would likely stagnate after that.

2.2.5 Pathway towards 2050

In the Current EU Trends Pathway, the development of blue hydrogen starts in the 2020s. Because of a steadily increasing EU ETS CO_2 allowance price from €20-25/tCO_2 to €35 €/tCO_2 by 2030, the gap to invest in CCS retrofits of SMR installations is reduced and increases the trust in the long-term business case. Modest national support (subsidy schemes) and EU funding (e.g. Innovation Fund) drive up the volume, reaching around 40 TWh of blue hydrogen by 2030 and 140 TWh and 150 TWh by 2040 and 2050, respectively. Such a development entails a conversion of all merchant hydrogen production facilities by 2040, 20% of the ammonia/methanol production and almost half of the hydrogen production in refineries by 2050.

Since almost all the expanded wind and solar electricity production in this pathway can still be used directly as electricity until 2030, the focus in green hydrogen developments is on reducing electrolyser cost by gradually increasing the scale, reaching 2 GW_e of installed capacity by 2030. This development is supported by FCH-JU, the EU Innovation Fund, and national R&D programs.

The deployment of green and blue hydrogen by 2030 is moderate, but the real shortcoming of the pathway is visible post-2030 where growth stagnates due to unfavourable boundary conditions. Policies that specifically target the production of green hydrogen and incentivise demand are sparse, which results in limited upscaling and consequent cost reductions for electrochemical hydrogen production. This assumes that scaling up outside of the EU is also moderate, because cost reductions occur as technology deploys in other parts of the world. Figure 4 illustrates that post-2030 a large gap emerges between the production of renewable and low carbon hydrogen production under current policies and what is needed to reach the Gas for Climate Optimised Gas end state of 1,710 TWh by 2050. With a production of 410 TWh in 2050 in this pathway, the level of renewable and low carbon hydrogen production only just above the current level of conventional hydrogen production in the EU (339 TWh).

40 Bloomberg (2019), *Hydrogen's Plunging Price Boosts Role as Climate Solution*, https://www.bloomberg.com/news/articles/2019-08-21/cost-of-hydrogen-from-renewables-to-plummet-next-decade-bnef

41 Assuming a discount rate of 5%, an economic lifetime of 30 years, plant output of 500 t H_2 per day and full load hours equal to 347 days per year.

42 Navigant (2019), *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*, https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

43 Navigant (2019), *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*, https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

2.3 Accelerated Decarbonisation Pathway – Hydrogen

Conclusion

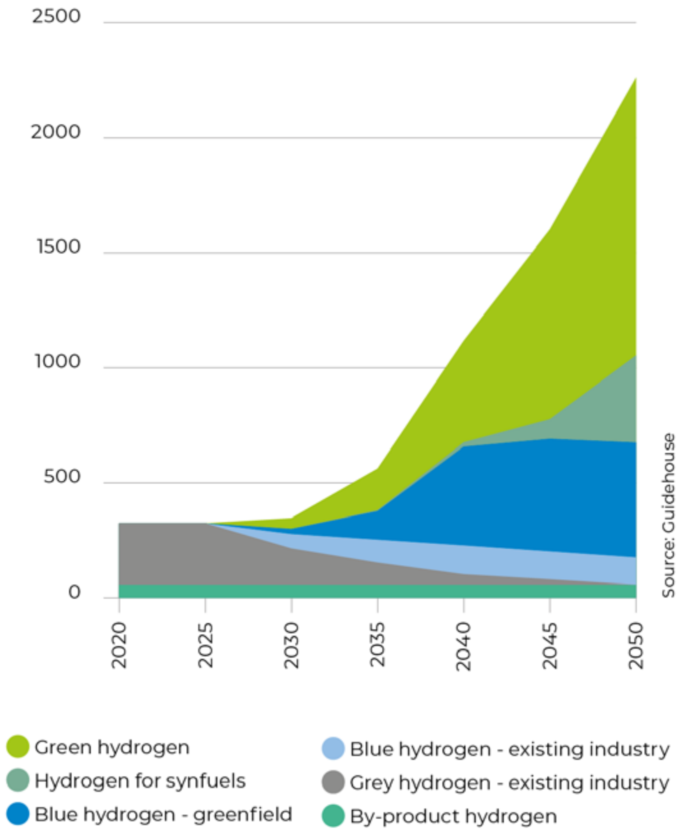
In the Accelerated Decarbonisation Pathway, an EU ETS price of €55/tCO_2 by 2030 is foreseen, which is likely to enable a more rapid conversion of conventional hydrogen plants to CCS and could even make greenfield blue hydrogen plants competitive with SMR plants without CCS. This development would likely see about half of the total existing SMR/ATR capacity retrofitted by 2040, providing a decarbonised hydrogen supply to existing end-uses of about 125 TWh by 2040. Blue hydrogen hubs are expected to develop first in industrial clusters around the North Sea where most of the existing hydrogen plants are located, with significant potential for offshore CO_2 sequestration nearby; here much of the infrastructure is already in place, including offshore gas pipelines which can potentially be repurposed to transport CO_2.

Furthermore, the increased emission reduction target of the EU Green Deal would see a more rapid decarbonisation of the power sector with more renewable power projects coming online prior to 2030. In 2020-2030, this would create more favourable boundary conditions for the production of green hydrogen, predominantly in southern Europe where solar power can already deliver power well below €20/MWhe today. From 2030 onwards, the increasing offshore wind capacity on the North Sea may feed into a combined electricity and hydrogen infrastructure to continuously serve demand in a large part of Europe. A European hydrogen backbone could emerge, connecting the early 'beachheads' in the industrial clusters. Aside from the EU ETS price, several national and EU policies are needed to drive these international, sector integrating developments.

Green hydrogen supply could reach around 50 TWh by 2030 (20-25 GW installed capacity) and would surpass the production of blue hydrogen in the early 2040s due to rapid cost reductions. Production costs of green hydrogen reach €44-€61/MWh by 2040, making it competitive with the production of blue hydrogen in SMR or ATR plants with CCS.

Under this scenario, it is likely that the EU will reach the role for green hydrogen as foreseen in the Gas for Climate 2050 end-vision.

Figure 5. Accelerated Decarbonisation Pathway for hydrogen deployment towards 2050. Implication of the EU Green Deal for hydrogen



Note that the supply in this figure exceeds the 1,710 TWh of the Gas for Climate 2050 Optimised Gas end state because supply is included from petrochemicals, which was previously out of scope, and production of synthetic fuels.

The implementation of the EU Green Deal would lead to a 55% reduction of greenhouse gas emissions by 2030 compared to 1990 levels. This kind of signal is expected to drive up the prices of EU emission allowances to a level of €55/tCO_2.[44] Such carbon price incentives would enable a more rapid conversion of conventional hydrogen plants to CCS and could even make greenfield blue hydrogen plants competitive with SMR plants without CCS. Capture, transport and storage from SMR plants is estimated at between €50-60/tCO_2 to break even.[45] With such an incentive and in combination with other forms of support around permitting, several proposed projects like H-vision, H21 North England, Porthos, and H2M could be fully operational by 2035.

At the same time, the EU Green Deal would see a more rapid decarbonisation of the power sector with more renewable power projects coming online up to 2030. From 2020-2030, this would create more favourable boundary conditions to produce green hydrogen, because in combination with other renewable sources, solar and wind power start to reach the limits of electricity demands for more hours in more places. After covering direct electricity demand, southern Europe, where solar power can already deliver power in the range of €0.015-€0.02/kWh, has a good starting position for ramping up green hydrogen production.

44 Carbon Tracker Initiative estimates that an increased EU climate target of minus 55% by 2030 would translate into an EU ETS price of about €55 per tonne of CO_2e by 2030, see: https://carbontracker.org/reports/carbon-clampdown/

45 Navigant (2019), *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*, based on IEA (2013) and GCCSI (2017).

To decrease pressure to aggressively add more renewable power in the EU to produce hydrogen, imports of hydrogen from North Africa could also gradually increase from 2030 to 2050, as suggested by EVP Timmermans in his hearing in the European Parliament.[46] Driven by the need to rapidly decarbonise and the limitations to ramping up wind and solar within the EU at the required speed, the transmission gas pipelines connecting South Europe and North Africa could be gradually converted to hydrogen-only carriers. Starting from 2030, hydrogen imports from North Africa could potentially provide up to a quarter of the total hydrogen supply by 2050, or around 450 TWh/year.

2.3.1 Technological and cost developments

Rapid upscaling of green hydrogen in the Accelerated Decarbonisation Pathway leads to a production cost of €44-61/MWh by 2050,[47] making it competitive with the production of blue hydrogen in SMR or ATR plants with CCS. This reduction in cost of green hydrogen production is driven by the declining costs of renewable power, increasing electrolyser efficiency and declining CAPEX due to economies of scale and technology learning. Researchers from Linz University found a learning rate for alkaline electrolysers of 11-13%, meaning a cost reduction of roughly 12% per doubling of installed capacity globally.[48] In the Accelerated Decarbonisation Pathway this is expected to drive down CAPEX for electrolysers from €715/kW in 2020 to €420/kW in 2050.[49]

The outlined development is expected to lead to green hydrogen starting to become cost-competitive with blue hydrogen just after 2040, since production costs for blue hydrogen are expected to increase from the current production cost of €37-42/MWh. These costs are expected to increase towards 2050 under the influence of carbon pricing[50] and increasing natural gas prices. Natural gas prices are historically low today, with European future contracts selling at around €15/MWh.[51] In line with the 2019 Gas for Climate study we maintain an assumption for the natural gas price of €30/MWh by 2050.

Cost developments for green hydrogen in the Accelerated Decarbonisation Pathway are also largely based on the scenario definition in the 2019 Gas for Climate study. However, in the meantime, various technology providers have claimed CAPEX for the present that are significantly below the €715/kW that was estimated at the time. For example, IEA cites a minimum cost of €450/kW for alkaline electrolysers.[52] We explore the effects of applying such lower-bound starting point together with more aggressive cost reductions in the Global Climate Action Pathway.

46 https://www.europarl.europa.eu/resources/library/media/20191009RES63850/20191009RES63850.pdf

47 Depreciation period: 30 years; Societal discount rate: 5%; OPEX (Including replacement, maintenance and labour costs): 3% of CAPEX per annum; system energy efficiency: 80% (LHV).

48 This excludes costs of transporting the hydrogen. Source: McKinsey (2019), *The hydrogen challenge: The potential of hydrogen in Italy*, SNAM

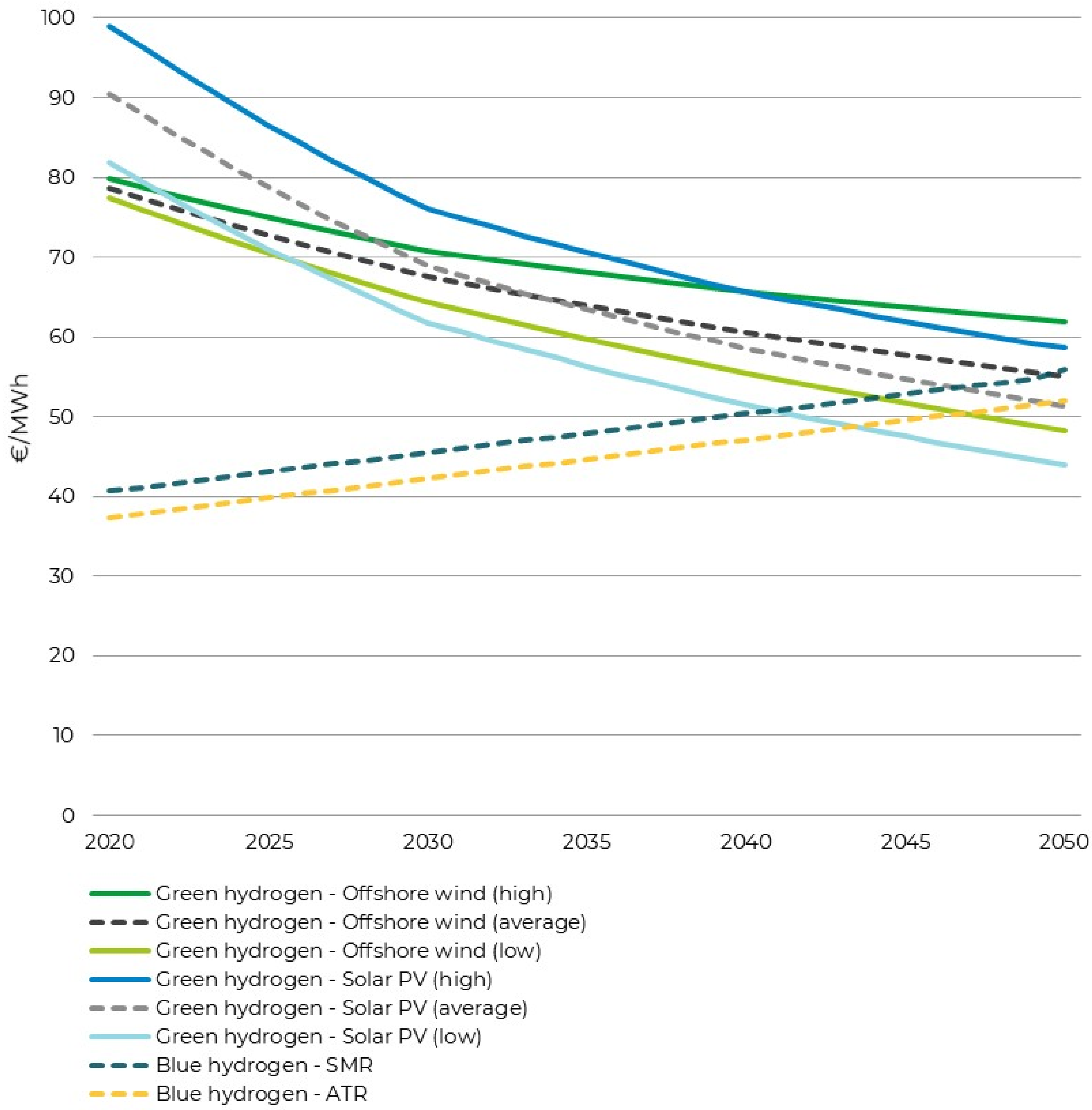
49 Navigant (2019), *Gas for Climate: The optimal role for gas in a net-zero emissions energy system.*

50 Even through SMR and ATR plants capture most of the produced CO_2, in practice this is up to 90-95% of the total. This means that these facilities will continue to be influenced by an increasing carbon price, although the effect is small. If the process would produce 8 tonnes of CO_2 per tonne of hydrogen and the capture equipment removes 90% of the CO_2, at a carbon price of €100/tCO_2 this would be €80 per tonne H_2 or €2.5/MWh.

51 EEX (2020), *Natural Gas Market Data*, https://www.eex.com/en/market-data/natural-gas/spot-market

52 IEA (2019), *The future of hydrogen*.

Figure 6. Development of technology costs for green and blue hydrogen in the Accelerated Decarbonisation Pathway (in €/MWh). Costs are all based on a 5% discount rate and 30-year economic lifetime.



Source: Guidehouse

2.3.2 Societal acceptance

It may be challenging to achieve societal acceptance of this pathway due to the significant amount of CO_2 sequestration required from blue hydrogen assets, as well as an increase in natural gas demand for hydrogen production compared to current levels. This natural gas is converted to hydrogen and decarbonised, but concerns exist around methane leakage in the upstream production and distribution of natural gas; these will need to be addressed.

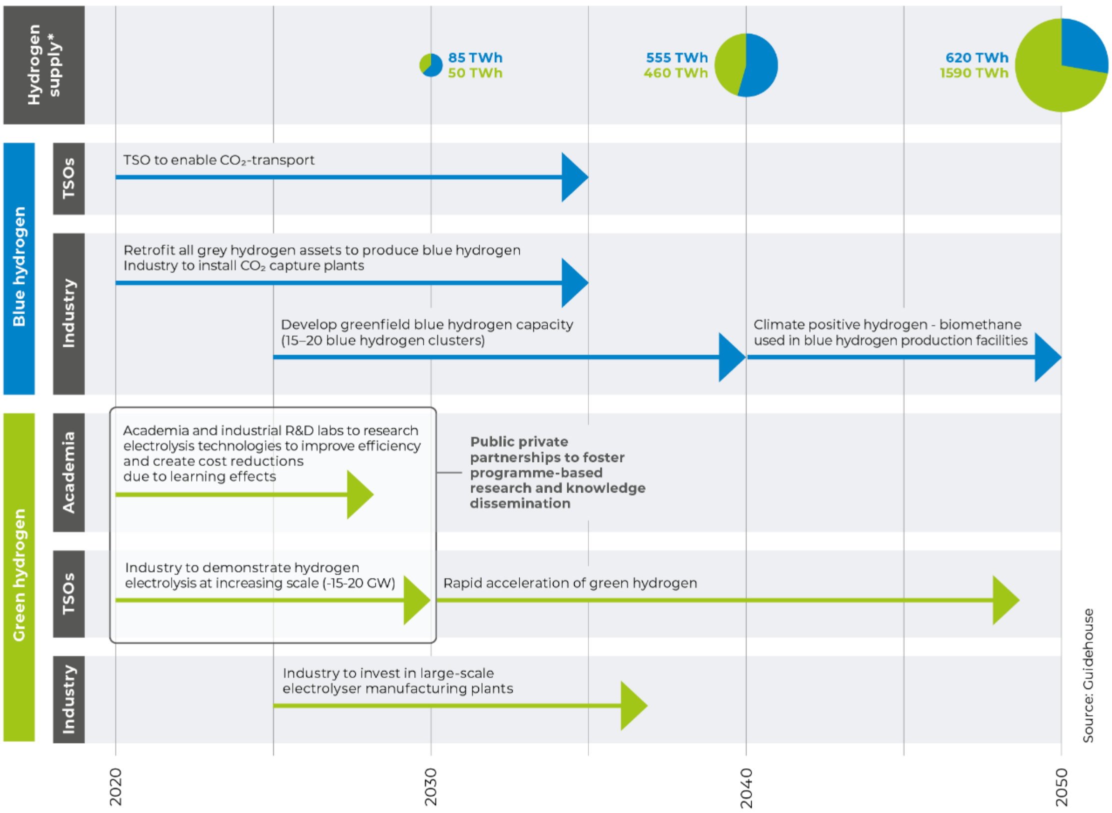
However, the benefit of this pathway in terms of social acceptance is that it demonstrates that all the hydrogen demand in the EU end-use sectors can be satisfied with domestic production, meaning that jobs and value added remain in the EU.

2.3.3 Pathway towards the 2050 Optimised Gas end state

With the Accelerated Decarbonisation Pathway, the Gas for Climate 2050 Optimised Gas end state comes into reach, with a green hydrogen supply of around 1,600 TWh and a blue hydrogen supply of around 600 TWh (Figure 5). When sufficiently stimulated, we believe that 20–25 GW of green hydrogen capacity could be reached by 2030 and 500-600 GW by 2050. This will be a combination of distributed and centralised hydrogen production sites with conversion efficiencies approaching 80% by 2050. Simultaneously, existing grey hydrogen plants would be rapidly retrofitted with CCS and greenfield blue hydrogen plants would be developed in a relatively short timeframe of 5-10 years.

Due to the significant demand for low carbon hydrogen in this scenario, already in the 2030-2040 timeframe, a significant scale-up of blue hydrogen is required because the energy system is not fully decarbonised yet by this period. Only when demand for direct use of low carbon electricity in end-use sectors is largely satisfied does it make sense to convert renewable electricity on a large scale to hydrogen. For this reason, the supply of blue hydrogen from greenfield plants in this pathway increases to 430 TWh by 2040 with moderate growth to around 500 TWh in 2050. This could, however, be lower or higher depending on the availability of green hydrogen at competing cost. In addition, the petrochemical industry and merchant hydrogen plants would see a full conversion to CCS, enabling a decarbonised supply for existing demand of around 120 TWh.

Figure 7. Critical timeline hydrogen supply



* *Note that the supply in this figure exceeds the 1,710 TWh of the optimal gas end-state because supply is included from petrochemicals (previously out of scope), and production of synthetic fuels.*

2.3.4 Critical timeline

Table 2. Critical timeline of hydrogen deployment

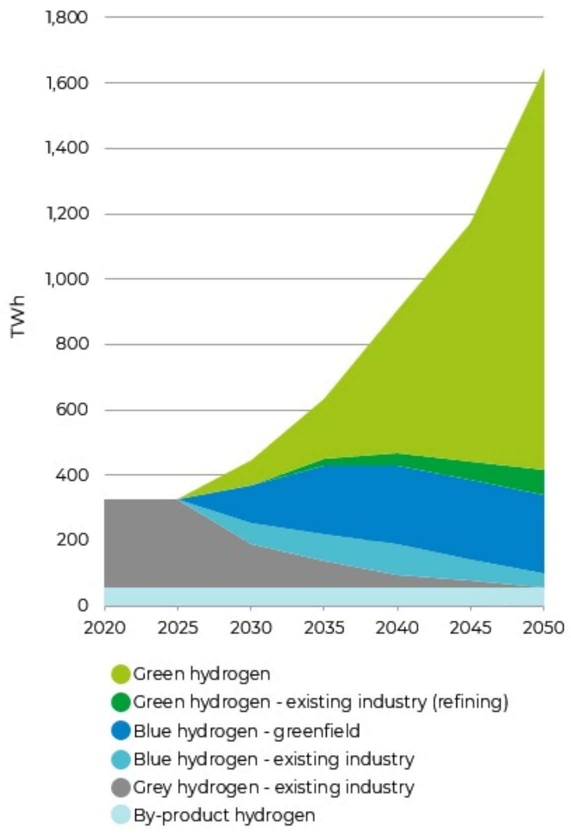
Pathway	Short-term (2020-2030)	Mid-term (2030-2040)	Long-term (2040-2050)
Current EU Trends	• Few green H_2 projects are developed (2 GW; 4 TWh). • Gradual retrofits of existing conventional H_2 with CCS (35 TWh).	• Gradual increase of green H_2 (50 TWh). • Steady growth of CCS retrofits in existing H_2 plants, all merchant plants converted by 2040 (80 TWh).	• Green H_2 deployment reaches 260 TWh by 2050. • Blue H_2 predominantly in existing industry (95 TWh), but also in new builds (adding up to 150 TWh).
Accelerated Decarbonisation (EU Green Deal)	• Faster upscaling of green H_2 (20-25 GW; 45 TWh). • Accelerated retrofits of existing conventional H_2 plants with CCS (60 TWh) and start with greenfield blue H_2 deployment (20 TWh).	• Ambitious acceleration of green H_2 (460 TWh). • Large share of conventional H_2 assets retrofitted with CCS (130 TWh) and greenfield blue H_2 ramps up significantly (430 TWh).	• Continued acceleration of green H_2 as it becomes more competitive compared to blue H_2 by 2040 (1,600 TWh). • Due to competitiveness of green H_2, retrofitted blue H_2 decreases slightly in industry (120 TWh); greenfield blue H_2 growth slows down (500 TWh).
Global Climate Action	• Rapid upscaling of green H_2 due to hydrogen backbone (20 GW wind; 35 GW solar; 77 TWh). • Ambitious short-term upscaling of new blue H_2 and retrofits (150 TWh).	• More ambitious acceleration of green H_2 mid-term (480 TWh), despite a lower demand for hydrogen. • Conventional H_2 retrofits and greenfield blue H_2 stagnate at 280 TWh due to increased competitiveness of green H_2 already around 2035.	• Continued growth of green H_2 as costs plummet well below that of blue H_2 (1,300 TWh). • Blue H_2 production remains at 280 TWh as alternative methods to produce blue H_2, like methane pyrolysis, become more competitive. • As low-cost production of green hydrogen increases globally, imports of synthetic fuels become an attractive alternative to producing those within the EU.

2.4 Global Climate Action Pathway – hydrogen

Conclusion Global Climate Action

In the Global Climate Action Pathway, technological breakthroughs are expected to lead to a rapid reduction of hydrogen production costs to €14-32/MWh by 2050, thanks to rapid reductions in electrolyser CAPEX and renewable power. Under these developments, green hydrogen is already cost-competitive with blue hydrogen in the 2030s, leading to a reduction in reliance on blue hydrogen to meet demand, which is already lower compared to Accelerated Decarbonisation due to a higher degree of electrification in end-use sectors. Blue hydrogen could also see cost reductions through the development of technologies like thermal methane pyrolysis or through the integration of green and blue hydrogen production systems. The development of methane pyrolysis depends on its ability to tap into markets for its by-product, carbon. As low-cost production of green hydrogen increases globally, imports of synthetic fuel and feedstocks become an attractive alternative to producing those within the EU, leading to a lower hydrogen demand compared to the Accelerated Decarbonisation scenario.

Figure 8. Global Climate Action Pathway for hydrogen deployment towards 2050.



Source: Guidehouse

Table 3. Key findings in the Global Climate Action Pathway

	Pathway
Imports	267 TWh of synthetic kerosene imports, meaning an embedded hydrogen demand of between 330-380 TWh, depending on conversion efficiency.
Green hydrogen	Production rapidly scales up to 1,300 TWh by 2050
Blue hydrogen	Due to competitiveness of green hydrogen, production stagnates at 280 TWh in 2040

Source: Guidehouse

2.4.1 Technological and cost developments

The production of green and blue hydrogen in the EU sees significant cost reductions compared to the €44-€61/MWh range for 2050 that is figure cited in the Accelerated Decarbonisation Pathway. Green hydrogen production costs in the EU plunge to a range of €14-€32/MWh (Figure 9). Cost reductions are achieved through four key developments:

- **Much lower electrolyser costs**: Based on recent insights, it appears that alkaline electrolysers can be built for much lower costs than was known when the Gas for Climate 2019 report was published, a year ago. This leads to a much lower potential electrolyser system cost across the 2020-2050 period:
  - IEA[53] has lower bounds of its cost ranges for electrolyser systems dropping from €450/kW in 2020, via €360/kW in 2030, to €180/kW in the long term, which for the Global Climate Action Pathway we will interpret as 2050.
  - BloombergNEF54 sees a convergence between prices in China (which they say are already around €180/kW) and those outside China, dropping from €105/kW in 2030 to €70/kW in 2050.
  - CAPEX per unit of hydrogen produced is further reduced due to increasing full load hours. It is expected that due to improved wind turbine technologies, deployment of higher hub heights and longer blades with larger swept areas the capacity factor for offshore wind will increase from the current average of 43% to 52% in 2050.[55]
- **More rapid reduction of renewable power production costs**: The Accelerated Decarbonisation Pathway showed only moderate cost reductions for renewable power towards 2050. The Global Climate Action Pathway explores more aggressive cost reductions as e.g. cited by Energinet for offshore wind and a study by Vartiainen et al. for solar PV. Energinet estimates that LCOEs for offshore wind could drop from €47/MWh in 2020 to €30/MWh by 2050, which includes the network connection costs that many governments facilitate. Excluding these costs yields an LCOE reduction of €37/MWh in 2020 to €20/MWh in 2050.[56] Solar PV LCOEs of €20/MWh are already common in southern Europe. The Global Climate Action Pathway assumes a reduction to €6/MWh by 2050 for southern Europe.[57]
- **Integration of green and blue hydrogen production systems**: ATRs generally use methane, pure oxygen, and steam to produce syngas. Operating independently, these plants need an air separation unit to supply oxygen to the process. Air separation to obtain oxygen is capital intensive and requires on average 200 kWh power to obtain 1 tonne of oxygen.[58] However, electrochemical production of green hydrogen produces a by-product stream of oxygen that can be used by the ATR. This leads to system cost savings and can reduce the cost of blue hydrogen production by €0.15/kg or around €5/MWh, leading to an upper-bound cost of €47/MWh in 2050 for ATR-based hydrogen production.[59]

53 IEA (2019), *Future of Hydrogen*

54 Bloomberg, 21 August 2019, *Hydrogen's Plunging Price Boosts Role as Climate Solution*, https://www.bloomberg.com/news/articles/2019-08-21/cost-of-hydrogen-from-renewables-to-plummet-next-decade-bnef

55 IRENA (2019), *Future of Wind*.

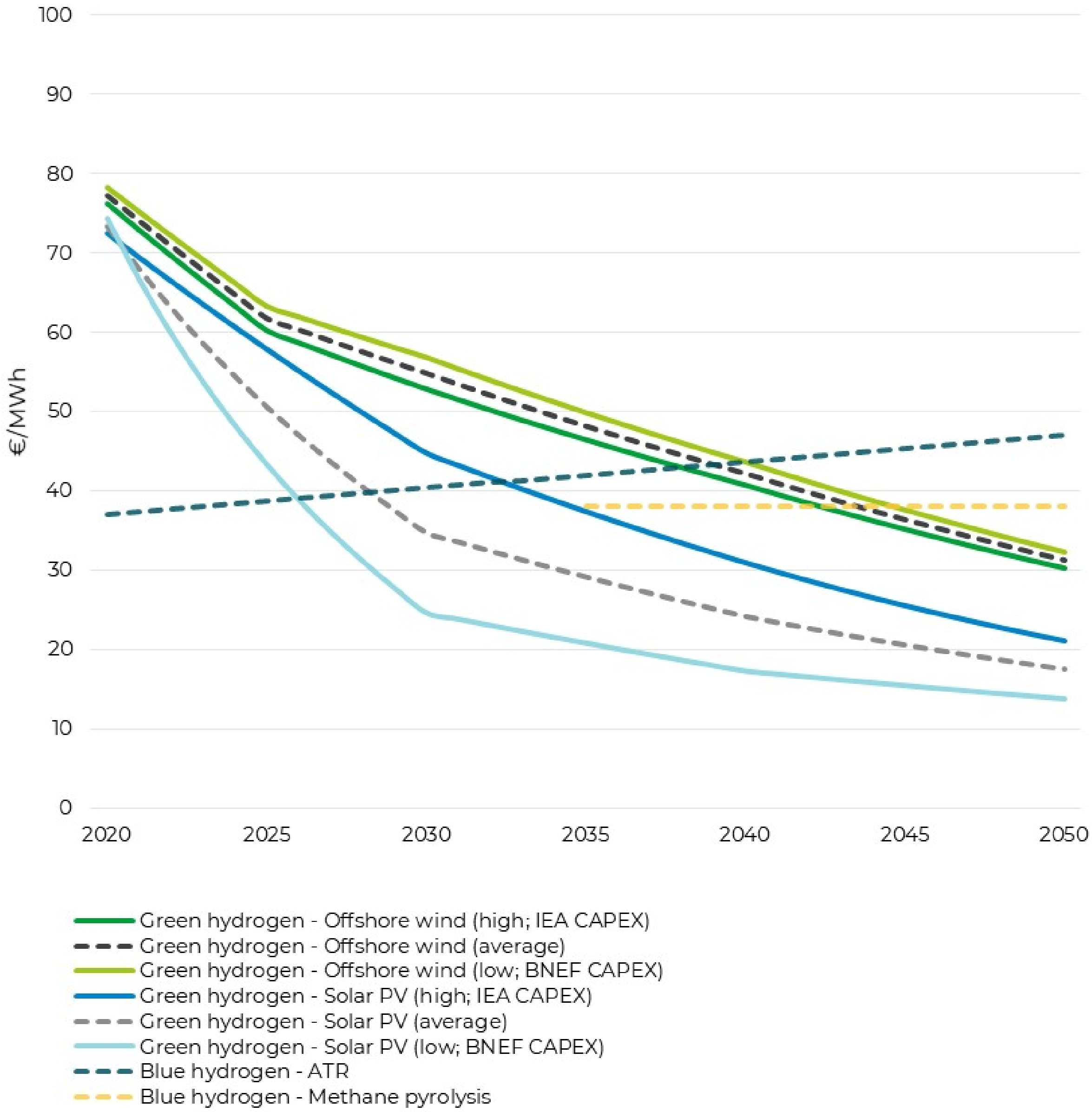
56 Energinet (2018), *Note on technology costs for offshore wind farms and the background for updating CAPEX and OPEX in the technology catalogue datasheets*, https://ens.dk/sites/ens.dk/files/Analyser/havvindsnotat_translation_eng_final.pdf

57 Vartiainen et al. (2019*), Impact of weighted average cost of capital, capital expenditure, and other parameters on future utility-scale PV levelised cost of electricity*, https://onlinelibrary.wiley.com/doi/epdf/10.1002/pip.3189

58 Darde (2009), Air separation and flue gas compression and purification units for oxy-coal combustion systems, Air Liquide, https://doi.org/10.1016/j.egypro.2009.01.070

59 Derived from Jakobsen & Atland (2016).

Figure 9. Technology cost developments of green and blue hydrogen in the Global Climate Action Pathway (in €/MWh)



Source: Guidehouse

- **Deployment of novel technologies and markets**: In the coming decades, thermal methane pyrolysis could become a new way to produce low carbon hydrogen from natural gas. Other innovations in hydrogen production include thermochemical splitting and photocatalysis. Specifically, thermal methane pyrolysis could have a noteworthy role to play in the global supply of low carbon hydrogen depending on the development of the technological barriers and the evolution of end-use markets. Companies like Gazprom and BASF are actively developing this technology. Since methane pyrolysis cracks methane into hydrogen and pure carbon, it is required to dispose of the carbon. For the economic competitiveness of the technology it is even crucial to find industrial end uses for the carbon, since without income from this by-product, the hydrogen produced is more costly than via SMR or ATR.[60] Currently, the main demand for elemental carbon would come from carbon black and graphite electrodes (19 Mt/year of carbon globally), but future demand expectations are high, leading to around 260 Mt/year by 2050 (Table 3). Such market could enable a production of up

60 Parkinson et al. (2018), *Hydrogen production using methane: Techno-economics of decarbonizing fuels and chemicals*, https://doi.org/10.1016/j.ijhydene.2017.12.081

to 2,900 TWh of blue hydrogen, of which some 300 TWh might be exported to Europe.[61] Alternatively, natural gas could be imported to Europe with the methane converted to hydrogen in Europe using methane pyrolysis, which eliminates hydrogen transport costs. Industry players like Gazprom predict they will be able to produce hydrogen at costs of €1.14/kg by 2050 (€38/MWh), with upside potential depending on the price received for carbon.[62] Concerns remain around methane pyrolysis' climate benefits, as the energy conversion efficiency of methane to hydrogen is only 55%. At moderate levels of leakage, a large part of the climate benefit would therefore be erased compared to conventional reforming.[63]

Table 4. Expected market developments for by-product carbon (in Mt).[64]

	2020	2025	2030	2035	2040	2045	2050
Graphite electrodes	2	3	3	4	5	6	8
Lithium ion	0	1	2	5	13	36	97
Carbon black	16	23	32	44	61	85	118
Carbon fibre	0	0	1	2	6	14	36
Carbon nanotubes	0	0	0	0	0	1	1
Total	**19**	**26**	**38**	**55**	**86**	**142**	**260**

Source: Guidehouse

Thanks to the collective global climate action in this scenario, Europe could also decide to engage in hydrogen imports from North Africa, potentially relieving pressure on its power grid from having to aggressively add more renewable power to produce green hydrogen. Gas infrastructure already exists which could be repurposed to transport hydrogen. Specifically, the Maghreb-Europe pipeline between Spain and Morocco (Naturgy/Galp Energia) could transport 12 bcm, Medgaz between Algeria and Spain (Sonatrach/Naturgy) 8 bcm whereas the Trans-Mediterranean pipeline between Italy and Tunisia/Algeria (Snam and partners) has a capacity of 30 bcm. McKinsey expects that green hydrogen production in North Africa will be around 14% less costly compared to production in Italy,[65] transport costs included, creating an incentive to fully utilise this existing infrastructure.

However, it should be mentioned that blending hydrogen into natural gas grids requires upgrades to the current infrastructure above specific thresholds and could raise issues at the end user side as certain appliances, burners, and especially industrial consumers of feedstock have limitations in what percentage of hydrogen they can take in[66], and the (unpredicted) variations they can accept. Directing blended hydrogen to applications that can accept a blend will be highly complex for gas operators; separating the hydrogen and methane into finer grids closer to the demand centres using membranes is being considered. Alternatively, imports of hydrogen increase with increments of about 50% per connection point, as both the Maghreb-Europe and the Trans-Mediterranean pipelines have double connections, and an additional connection of 8 bcm in Medgaz.[67] In addition, the current RED does not allow imported green hydrogen to count towards the EU renewables target, whereas imported renewable electricity from other countries can already be counted towards the RED and are more likely to be subsidised by EU member state incentive schemes. This creates an unequal level playing field for imported green hydrogen. Together, existing pipelines have a potential to deliver around 450 TWh/year of hydrogen to Europe, which could be fully used by 2050 but is not included in our scenario.

2.4.2 Societal acceptance

Societal acceptance of this pathway may be challenging due to the significant scale-up of blue hydrogen in the short term, and the related CO_2 sequestration that would be required.

61 Assuming that Russia will be able to tap into the global end-use market for carbon products with a share of 16%, equal to the expected share of Russia in global gas production. It is assumed that exports to Europe could follow the same share as the expected gas exports, decreasing from 83% in 2017 to 63% in 2040. Source: BP World Energy Outlook 2019.

62 IFRF (2018), *Gazprom investigating low carbon hydrogen supply to Europe*, https://ifrf.net/combustion-industry-news/gazprom-investigating-low carbon-hydrogen-supply-to-europe/

63 Weger (2017), *Methane cracking as a bridge technology to the hydrogen economy,* https://www.sciencedirect.com/science/article/pii/S0360319916333213

64 Sources: PR Newswire, Market Watch, Composites Worlds, Mordor Intelligence.

65 McKinsey (2019), *The hydrogen challenge: The potential of hydrogen in Italy*, SNAM

66 Marcogaz - Overview of test results & regulatory limits for hydrogen admission into existing natural gas infrastructure & end use https://www.marcogaz.org/app/download/8105290863/TF_H2-427.pdf?t=1574766383

67 Medgaz (2019), *What's the pipeline's transport capacity?,* https://www.medgaz.com/medgaz/pages/faqs-eng.htm

2.4.3 Pathway towards 2050

The Global Climate Action Pathway is characterised by a significantly lower long-term demand for renewable and low carbon hydrogen mainly due to imports of synthetic fuels and feedstocks (such as methanol) from outside the EU, and a rapidly decreasing cost for green hydrogen.

In the short term, demand for decarbonised hydrogen in end-use sectors increases rapidly, which means that both green and blue hydrogen production need to significantly ramp-up. Green hydrogen production is significantly higher by 2030 compared to Accelerated Decarbonisation at 77 TWh, with the majority coming from cheap solar PV in southern Europe. Because green hydrogen remains constrained by the power grid, blue hydrogen needs to meet the rest of the demand leading to a ramp-up to 150 TWh, of which 60 TWh retrofits of existing SMR installations in, e.g. refineries and ammonia/methanol plants.

Because green hydrogen production costs are already competitive with blue hydrogen in the 2030s, most of the subsequent growth comes from green hydrogen, leading to 480 TWh of supply in 2040. This is higher than in the Accelerated Decarbonisation Pathway, despite a lower demand from end-use sectors and synthetic fuels being imported in Global Climate Action. The low cost of green hydrogen in this pathway even enables the replacement of hydrogen plants in refineries to decentralised electrolysers, making up 78 TWh of the 1,300 TWh green hydrogen.

3. Buildings Decarbonisation Pathways

Key Takeaways

- Under the Current EU Trends Pathway, we expect light renovation efforts of buildings in line with the current situation (renovation rates between 1% and 1.5% of mostly light and medium renovations), but a limited share of deep renovations towards 2030. Increasing the renovation speed and depth after 2030 to compensate for the lack of renovations between 2030 and 2050 will be a near impossible, task. Without the right insulation levels, the needed low carbon heating technologies are more difficult to apply at a level in line with the Gas for Climate 2050 Optimised Gas end state. Full electric heat pumps are unlikely to be applied on the expected level due to a limited amount of deep renovated buildings, and hybrid heating solutions will require more energy use and produce a higher stress on energy infrastructure if the buildings are poorly insulated.

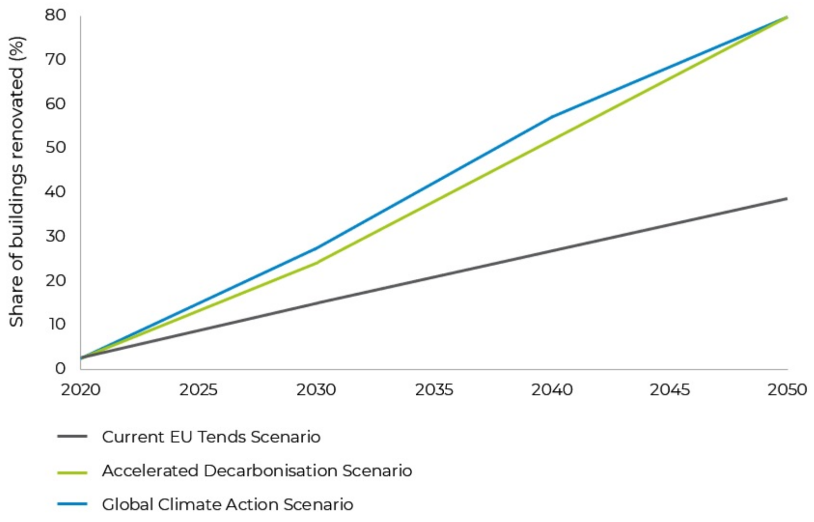
- The Accelerated Decarbonisation Pathway envisions a significant increase in energy renovation rates towards 2030 (to between 2.5% and 3% per year) to reach net-zero emissions, as in the Gas for Climate 2050 Optimised Gas end state. Focused policies such as long-term renovation targets and increasing required minimal energy performance levels of existing buildings could help reach this goal. In addition, increasing knowledge build-up around low carbon buildings, reducing hassle for building owners, and supporting financing options are required to create the right environment. A more focused push to switch to low carbon heating technologies in well-insulated buildings is necessary to get to the right pathway.

- The Global Climate Action Pathway includes significant cost reductions to insulation and heating technologies could speed up the renovation process by creating a situation in which energy renovations occur outside of normal renovation cycles. Faster and more convenient renovations and a wider range of renovation options enables a rapid scale-up towards the Gas for Climate Optimised Gas 2050 end state. Introduction

3.1.1 Current situation

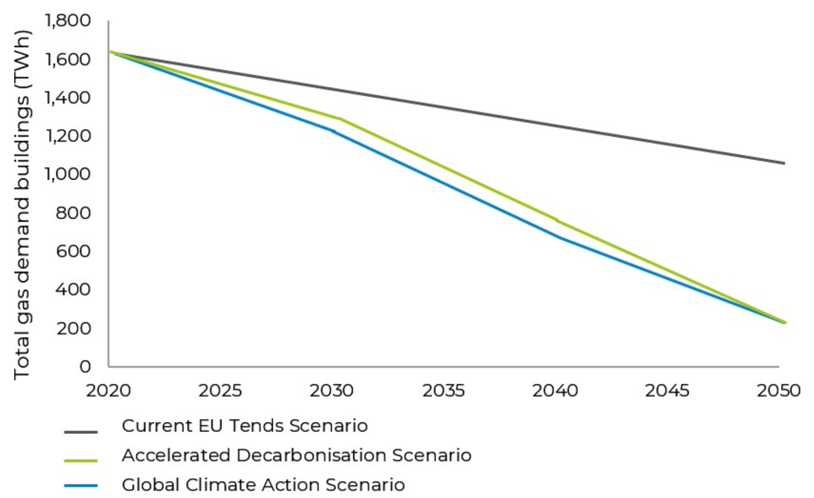
Buildings are Europe's largest energy consumer, responsible for about 40% of the EU's energy consumption.[68] Energy is used for space heating, domestic hot water, cooking, cooling, and appliances. While cooling and appliances are mostly electricity-based, space heating, domestic hot water and cooking are provided by a wide range of different energy carriers, such as gas, biomass, electricity, coal, and oil. The use of heating technologies differs significantly per member state. For example, the Netherlands' natural gas demand for residential heating is 84% of total heating demand while in Italy it is 57%, and in Germany it is 42%.[69] The availability of energy sources and access to infrastructure play a large role here.[70]

Figure 10. Development of share of buildings renovated in the various pathways.



Source: Guidehouse

Figure 11. Development of total gas demand for buildings in the various pathways.



68 European Commission, *Energy performance of buildings directive*, https://ec.europa.eu/energy/en/topics/energy-efficiency/energy-performance-of-buildings/energy-performance-buildings-directive#facts-and-figures.

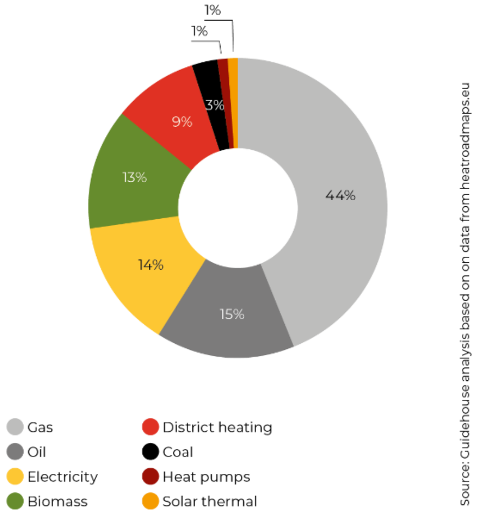
69 Based on data from heatroadmaps.eu, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.

70 E.g. the Netherlands has a huge natural gas resource in the northern part of the country.

Source: Guidehouse

Currently, the built environment uses about 3,600 TWh[71] for heating and domestic hot water. Almost half of this energy demand is from natural gas, while the other half is from a variety of energy carriers, like oil, biomass, electricity, and district heating (Figure 12). When gas is used, it is almost solely in gas-fired boilers, with limited application of hybrid heat pumps and fuel cells. However, there are obligations to combine fossil boilers with solar thermal energy to reduce consumption of gas and oil in some regions.

Figure 12. Current share of energy carriers in heating and domestic hot water in the built environment[72]



Reducing the buildings' heat demand through improving the efficiency of the building envelope is essential to the decarbonisation of the buildings sector. For building efficiency, the EU uses an energy label system for buildings. For instance, from label A for the lowest energy demand to label G for the highest energy demand. A 2017 study by BPIE[73] showed that only 3% have an energy label A, while almost 50% of buildings have a label of D or below. Buildings with energy label A are necessary to effectively implement low carbon heating technologies such as heat pumps. However, the current average EU annual weighted energy renovation rate[74] for residential and non-residential buildings is only around 1% with a limited share of deep renovation. [75,76] The application of full electric heat pumps is relatively small, although gaining momentum, while the application of hybrid heat pumps and fuel cells is limited.

3.1.2 Gas for Climate 2050 Optimised Gas end state

A huge effort is required to achieve a decarbonised buildings sector. Changing to low carbon heating technologies requires a big increase in energy efficiency. The application of heat pumps benefits from low heat distribution temperatures within a building. This is only economically feasible if buildings have enough insulation to reduce heat demand, allowing for low temperature heating distribution to provide enough heat to the building. Applying proper insulation will also help reduce renewable energy demand in the building sector. Energy renovations are the first step to a low carbon, built environment. These renovations are often combined with regular renovation activities such as replacement of roof, windows, or the heating

71 Based on data from heatroadmaps.eu, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.

72 Based on data from heatroadmaps.eu, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.

73 BPIE, "97% of buildings in the EU need to be upgraded," 2017, http://bpie.eu/wp-content/uploads/2017/12/State-of-the-building-stock-briefing_Dic6.pdf.

74 Energy renovations are applied in various depths, like light, medium and deep renovation. The weighted energy renovation rate describes the annual reduction of primary energy consumption, within the total stock of buildings (residential or non-residential respectively), for heating, ventilation, domestic hot water, lighting (only non-residential buildings) and auxiliary energy, achieved through the sum of energy renovations of all depths.

75 European Commission, 2019. Accelerating energy renovation investments in buildings. Available at: https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/accelerating-energy-renovation-investments-buildings

76 Ipsos and Navigant, 2019. Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU, pages 15-17. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/1.final_report.pdf.

installation, where energy efficiency is improved at the same time. In most cases, this is also required because reducing energy use is rarely cost-effective (compared to adding energy saving measures on an already planned renovation). It is estimated that 97%[77] of the buildings will require a partial or full renovation to achieve the 2050 decarbonisation vision.

A huge effort is required to achieve a decarbonised buildings sector. The Gas for Climate 2019 study included a buildings decarbonisation analysis and concluded that, overall energy use for heating and hot water could reduce significantly from 3,600 TWh to just over 1,000 TWh by mid-century. Achieving these energy reductions require energy renovation in almost all buildings. In the Gas for Climate 2050 Optimised Gas end state, existing buildings with a gas connection today will continue to use gas by 2050 (37%), but in strongly reduced volumes. Gas (mainly biomethane and some hydrogen) will be used in hybrid heat pumps with electricity.

Hybrid heat pumps provide a lot of flexibility with their combination of efficient electric and gas heating and could significantly reduce stress on the electricity grid during winter peak demand times. The application of heat pumps currently is almost solely focused on full electric heat pumps. Towards 2050, it will be important to actively support the hybrid heat pump as logical alternative to full electric heat pumps to prevent electricity grid issues in a low carbon future and to ensure a cost-efficient decarbonization of buildings with existing gas grid connections.

Box 3. The value of hybrid heating solutions

Hybrid heating solutions are a key factor in achieving a cost-effective, zero-carbon built environment in the Gas for Climate study. Hybrid heat pumps are a combination of a small heat pump and a gas boiler. This combination reduces insulation costs (no need for very deep renovation of the building envelope) and heating technology costs (application of smaller heat pumps and no need for low temperature floor heating), while requiring only a small amount of renewable gas. It also reduces stress on the electricity infrastructure: at low temperatures the efficiency of electric heat pumps reduces by up to 75%, which can be counterbalanced by use of renewable gas.
Hybrid heat pumps enable a robust pathway, since insulation, installing the heat pump, and decarbonising electricity and gas can take place independently, gradually reducing emissions. When installed, they provide system operators with increased resiliency by allowing shifting demand from electricity to gas and vice versa.
There is currently a limited application of this combination, and specific policy support is required for this technology to scale-up. Examples of policy support include focusing on information and knowledge dissemination, standardising the application of this combination, and ensuring the option is considered when developing renovation plans.

Buildings without a gas connection in 2050 will be heated by all-electric heat pumps (43%) or through district heating (20% of all buildings).

Since deep renovations are essential for heating buildings at low temperatures by all-electric technologies, significant renovation efforts are needed for buildings without gas connections. If renovation efforts stay behind, this hinders the deployment of all-electric and (to a lesser extent) hybrid heat pumps. In this case, it will be important to keep considering possible alternatives: to focus less on insulation and more on other renewable heating technologies, like hydrogen fuel cells, gas heat pumps, or boilers.

District heating already covers a significant share of the current mix for heating and has the potential to provide a considerable part of the built environment with renewable heat,[78] but is still largely based on (waste) energy from fossil-fuelled processes. In the future energy system, district heating networks play an important role in integrating the electricity, gas, and heating energy systems. Through the deployment of multiple heat supply technologies together, heat can be provided in a cost-effective and flexible way. Potential sources for district heating include geothermal heat plants, boilers, heat pumps, combined heat and power (CHP) plants, or fuel cells. CHP plants could use various types of inputs including hydrogen.

Cooling of buildings will be based on electric cooling appliances. As opposed to demand for heating, demand for cooling correlates well with the availability of renewable electricity for solar PV. In moments of cooling demand with less availability of electricity form solar PV, for example, in the evening, short-term electricity storage can be applied to bridge the peaks in a diurnal cycle.

77 BPIE, "97% of buildings in the EU need to be upgraded," 2017, http://bpie.eu/wp-content/uploads/2017/12/State-of-the-building-stock-briefing_Dic6.pdf.

78 In the Gas for Climate 2019 study we envision an increase in district heating from around 10% nowadays towards 20% in 2050. According the Heat Roadmap Europe district heating could increase from today's level of 10% up to 50% by 2050. Heat Roadmap Europe, 2019. About the Project. Available at: https://heatroadmap.eu/project/.

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3.2 Buildings pathway under current EU climate and energy policies

Conclusion Current EU Trends

Under the Current EU Trends Pathway, we expect light renovation efforts of buildings in line with the current situation (renovation rates between 1% and 1.5% of mostly light and medium renovations), but a limited share of deep renovations towards 2030. After 2030, increasing the renovation speed and depth to compensate for the lacking renovations between 2030 and 2050 will be a near impossible, task. Without the right insulation levels, the needed low carbon heating technologies are more difficult to apply at a level in line with the Gas for Climate 2050 Optimised Gas end state. Full electric heat pumps are unlikely to be applied on the expected level due to a limited amount of deep renovated buildings, and hybrid heat pumps will require more energy use and produce a higher stress on energy infrastructure if the buildings are poorly insulated.

3.2.1 EU policies

The EPBD[79] is the central policy in place to guide the EU energy transition in the built environment. The main aspects of this directive are:

- Requires member states to develop energy performance certificates (or energy labels) that are required for the sale of rental of buildings.
- Requires member states to set minimum energy performance requirements for building elements that are replaced or retrofitted, considering the cost-optimality of the requirements (Article 4).
- Sets strict requirements around new buildings, to reduce energy demand and increase renewable energy production in and around buildings (nearly net-zero energy buildings).

79 European Council, “Directive (EU) 2018/844 of the European Parliament and of the Council of 30 May 2018 amending Directive 2010/31/EU on the energy performance of buildings and Directive 2012/27/EU on energy efficiency,” 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1529483556082&uri=CELEX:32018L0844.

- Requires a smart readiness indicator that assesses the capability of the building to adapt to needs of the occupant, while optimising energy efficiency and overall performance and adapting to grid requirements.

However, the EPBD does not set mandatory targets for improving the energy performance of existing buildings.[80] Instead, some legislation supporting the development of renovation targets is set in the Energy Efficiency Directive (EED):

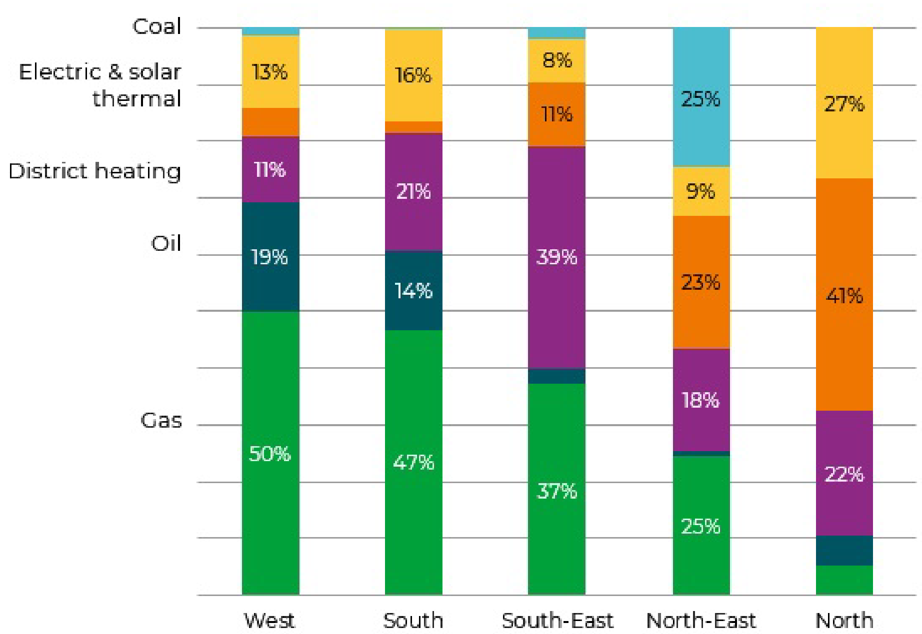
- The EED sets a 3% renovation target for buildings owned and occupied by governments and requires these buildings to be renovated to at least the minimum energy performance requirement from the EPBD.
- It requires member states to establish Long-Term Renovation Strategies (LTRS)[81] to mobilise investment in the renovation of the building stock and to update this strategy every 3 years.

A recent review[82] of the 2017 LTRSs of each member state showed that 90% of the strategies were considered compliant with the EED, but only about half of the strategies have long-term targets towards 2050.

3.2.2 Regional differences

There are large differences between countries in Europe in how buildings are heated. While gas provides the highest share of heating demand in western and southern Europe, in the southeast there is more focus on biomass. There is a significant share of coal in the northeast; in northern Europe, district heating is the largest heating demand technology. The current situation and available infrastructure will guide the required legislation towards a low carbon, built environment.[83]

Figure 13. Share of residential heating energy demand per carrier in 2015



Source: Navigant analysis based on HeatroadmapsEU [84, 85]

80 European Council for an Energy Efficient Economy (ECEEE), "Frequently Asked Questions on the Recast of the Energy Performance of Buildings Directive," https://www.eceee.org/policy-areas/Buildings/faqs-on-the-epbd/.

81 While originated in the EED, the LTRS have been moved to the EPBD in the 2018 update of the EPBD.

82 Joint Research Center, *Assessment of second long-term renovation strategies under the Energy Efficiency Directive*, 2019, https://op.europa.eu/en/publication-detail/-/publication/e04473ed-2daf-11e9-8d04-01aa75ed71a1/language-en/format-PDF/source-86607487.

83 Based on data from heatroadmaps.eu, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.

84 Based on data from heatroadmaps.eu, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis. Cooling demand assumed to be negligible.

85 West: Austria, Germany, Netherlands, Belgium, Luxembourg, France, UK, and Ireland. South: Portugal, Spain, Italy, Greece, Cyprus, Malta. South-East: Slovenia, Croatia, Hungary, Romania, Bulgaria. North-East: Slovakia, Czechia, Poland, Lithuania, Latvia, Estonia. North: Denmark, Sweden, Finland.

Even within regions there can be big differences in the approach to decarbonisation. For example, in Northern Ireland, there are subsidies for converting heating systems from oil to natural gas,[86] while in the Netherlands, there is a ban from connecting new buildings to the gas grid that was issued in 2018.[87] The Dutch government assigned a budget of €435 million between 2018 and 2028[88] for experiments to disconnect entire neighbourhoods from natural gas-based heating.

3.2.3 Technological developments

One of the reconditions of installing (hybrid) heat pumps is an increased insulation of buildings. The depth of buildings energy renovation determines how extensive the renovation is. An energy renovation can be broad spectrum, from changing one component to fully renovating a building. A study by Ipsos and Navigant[89] proposes the following definitions for energy renovations:[90]

- Below threshold (below 3% primary energy savings)
- Light renovations (between 3% and 30% primary energy savings)
- Medium renovations (between 30% and 60% primary energy savings)
- Deep renovations (above 60% primary energy savings)

To renovate a building to Gas for Climate Optimised Gas 2050 end-state levels, hybrid heat pumps and district heating require medium renovations and all-electric heat pumps require deep renovations. The current shares of these renovations are shown in Table 5.

Table 5. Renovation rates for medium and deep renovations

Renovation depth	Residential	Commercial
Medium renovation	1.1%	2.1%
Deep renovation	0.2%	0.3%

Source: Ipsos and Navigant, 2019. Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU

Table 5. shows that deep renovations are lacking significantly. While 43% of buildings in the 2050 end state should have deep renovations, not even 10% of the buildings will have this at the current building rate. The renovation sector is dominated by small, step-by-step[91] measures, where the focus is on cost-effective measures and insulation levels. If these step-by-step measures are significantly ramped up, this could bring us to the required insulation levels. However, it is more likely that it leads to selecting easy opportunities and that a significant share of buildings will never reach medium or deep renovation depths.

There are market initiatives to innovate in the deep renovation of buildings. For example, the Dutch initiative Energiesprong,[92] originally a government-funded innovation programme, has developed an approach to provide a whole house refurbishment, including local renewable energy production and a funding mechanism. Energiesprong has refurbished over 5,000 homes in the Netherlands and is also active in France, the UK, Germany, and Italy.

Next to renovations, low carbon heating technologies are also in need of development. For example, district heating already has a significant share of heat demand in Europe (Figure 12, Figure 13), but a large part of this is done based on waste heat of fossil-fuelled power plants. In view of a low carbon power sector, it is likely that a significant share of these power plants could be phased out between now and 2050. Alternatives to providing heat to district heating are in development, such as geothermal and solar thermal heat. For example, Denmark had 1.3 million m^2 of solar thermal panels connected by the end

86 Energy Saving Trust, "Financial support for home energy efficiency," https://www.energysavingtrust.org.uk/home-energy-efficiency/financial-support.

87 Staatsblad van het Koninkrijk der Nederlanden, 2018. Besluit van 26 april 2018 tot vaststelling van het tijdstip van inwerkingtreding van de Wijziging van de Elektriciteitswet 1998 en van de Gaswet (voortgang energietransitie). Available at: https://zoek.officielebekendmakingen.nl/stb-2018-129.html.

88 Rijksoverheid, s.d. Bestaande woningen aardgasvrij maken. Available at: https://www.rijksoverheid.nl/onderwerpen/aardgasvrije-wijken/bestaande-gebouwen-aardgasvrij-maken.

89 Ipsos and Navigant, 2019. Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU, table 2 and 3. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/1.final_report.pdf.

90 The scope of these energy renovations includes all building specific energy use, such as heating, domestic hot water, cooling and lighting and excludes (domestic) appliances. Heating will often be the main part of energy savings in renovations.

91 Step-by-step measures or renovations means renovations are done over a couple of years with individual building components, e.g. one year the roof, another year the windows and another year the heating system. This is in contrast to renovation where multiple (or all) building components are renovated at the same time.

92 Energiesprong, s.d. Energiesprong explained. Available at: https://energiesprong.org/about/.

of 2017.[93] Geothermal district heating is already applied in various European countries, such as Denmark, France, and Hungary.[94]

The heat pump market is in development, with high yearly growth rates (more than 10% per year between 2014 and 2017[95]). There are several developments in this market, such as new and more environmentally friendly working fluids, application of heat pumps in combination with low temperature heat grids, and the application of heat pumps for the production of higher temperatures. However, heat pumps are still a small part (~1%) of the heating market. The application of hybrid heat pumps is limited, but it is a promising technology—especially for buildings where it would be costly to achieve high insulation levels which would allow to install full electric heat pumps.

3.2.4 Pathway towards 2050

The European Commission developed a group of scenarios (the EUCO scenarios) to estimate the potential impact of EU climate and energy targets for 2030. The most recent is the EUCO 3232.5 scenario,[96] which shows the EU's final energy demand in the residential and tertiary sectors totalling 5,676 TWh in 2015. However, this includes all types of energy use in the built environment such a heating and electricity for appliances and cooking. The Gas for Climate analysis focusses only on space heating and domestic hot water, which represent about 80%[97] of total energy use in the residential buildings and about 50% in commercial buildings.[98] Assuming these shares, the EUCO 3232.5 shows the following development for heating demand and domestic hot water towards 2030,[99] as shown in Figure 14.

93 Z. Tian et al., 2019. Large-scale solar district heating plants in Danish smart thermal grid: Developments and recent trends. Available at: https://www.sciencedirect.com/science/article/pii/S0196890419303759.

94 Geothermal District Heating, s.d. Developing geothermal district heating in Europe, pages 51-55. Available at: https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/geodh_final_publishable_results_oriented_report.pdf.

95 European Heat Pump Association, 2018. Heat Pumps Integrating Technologies to decarbonize heating and cooling https://www.ehpa.org/fileadmin/user_upload/White_Paper_Heat_pumps.pdf.

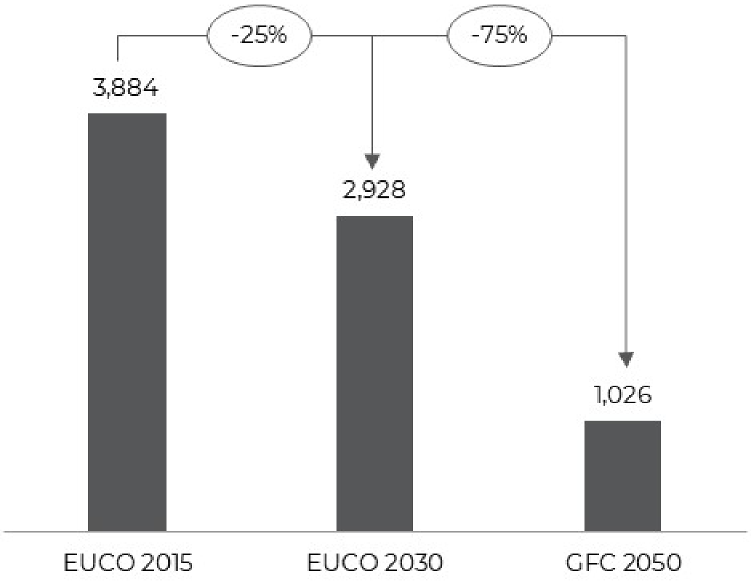
96 European Commission, 2019. Technical Note: Results of the EUCO3232.5 scenario on Member States, page 6. Available at: https://ec.europa.eu/energy/sites/ener/files/technical_note_on_the_euco3232_final_14062019.pdf.

97 European Commission, s.d. Energy consumption by end-use. Available at: https://ec.europa.eu/energy/en/content/energy-consumption-end-use.

98 Share of electricity use in commercial buildings is about 50% of total final energy demand. Although a part of this may be used for heating, most of it is likely for appliances and cooling demand (both out of scope). Eurostat, complete energy balances. Available at: https://appsso.eurostat.ec.europa.eu/nui/show.do?query=BOOKMARK_DS-1015839_QID_-6D663E68_UID_-3F171EB0&layout=SIEC,L,X,0;NRG_BAL,L,Y,0;TIME,C,Z,0;UNIT,L,Z,1;GEO,L,Z,2;INDICATORS,C,Z,3;&zSelection=DS-1015839GEO,EU28;DS-1015839UNIT,KTOE;DS-1015839INDICATORS,OBS_FLAG;DS-1015839TIME,2015;&rankName1=UNIT_1_2_-1_2&rankName2=INDICATORS_1_2_-1_2&rankName3=TIME_1_0_0_1&rankName4=GEO_1_2_1_0&rankName5=SIEC_1_2_0_0&rankName6=NRG-BAL_1_2_0_1&rStp=&cStp=&rDCh=&cDCh=&rDM=true&cDM=true&footnes=false&empty=false&wai=false&time_mode=NONE&time_most_recent=false&lang=EN&cfo=%23%23%23%2C%23%23%23.%23%23%23

99 There is a slight deviation between the HeatroadmapsEU figures and the EUCO figures for 2015, which is likely due to a combination of a small difference in scope and the assumed percentage shares used for calculating the space heating and domestic hot water heating used on the EUCO figures.

Figure 14. Energy use [in TWh] for space heating and domestic hot water from EUCO 2015 and 2030 and gap towards the Gas for Climate 2050 end state



Source: Guidehouse

Figure 14 shows that even with current policies, we will reach one-third of the reduction towards the target in the first 15 years, leaving two-thirds for the last 20 years. As it is likely that easy opportunities will be selected first (between 2015 and 2030), it is unlikely that current policies will almost double the energy reduction rates towards 2050. This is in line with the Heat Roadmap EU scenario for baseline demand,[100] which expects an approximate energy reduction of 20% between 2015 and 2030 and only a 30% reduction between 2015 and 2050.

Looking at the EU's current rate of energetic improvement, even the 25% towards 2030 may be unlikely. In a recent report from Ipsos and Navigant,[101] it is estimated that primary energy savings in the built environment are only at 1% per year. Between 2015 and 2030, this would only result in 15% (primary) energy savings.

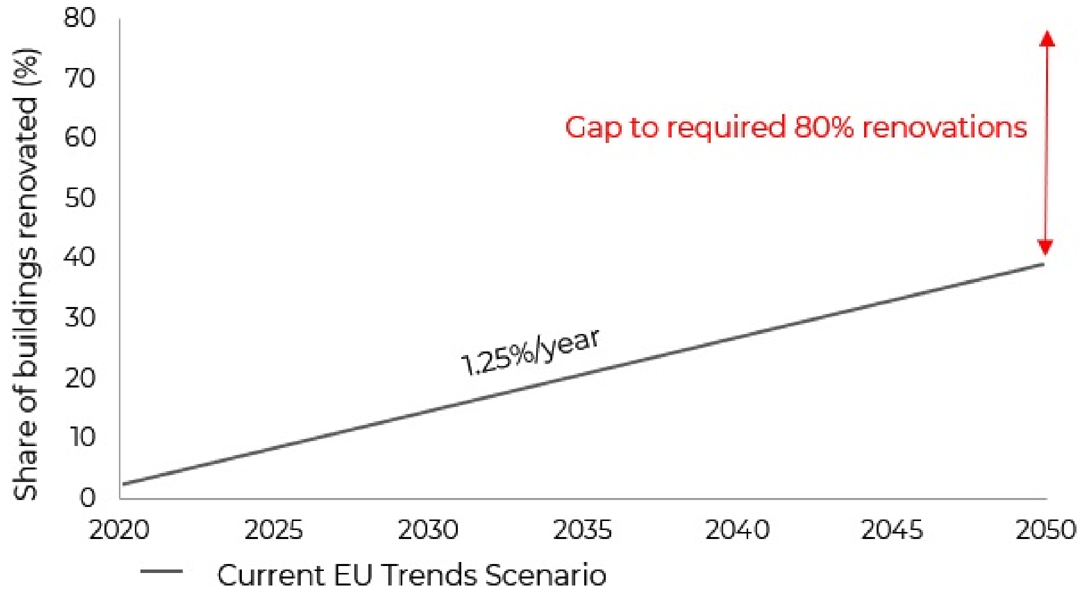
To reach the Gas for Climate 2050 Optimised Gas end state, it is insufficient to only look at total energy use, as this is a combination of energy savings due to insulation and energy reduction due to more efficient heating technologies. If 50% of energy demand is reduced, this could be because all buildings have a 50% reduction in final heat demand through improvements in the building envelope, or due to every building improving the efficiency of its heating technology by a factor of two.

Renovations of all non-efficient buildings is the issue that must be addressed. As mentioned, 97% of existing buildings in 2017 are estimated to require renovation and 75%-90% of these buildings will still be present in 2050. Averaging those percentages, a total of about 80% of existing buildings will require a renovation. The current renovation rate is between 1% and 1.5% per year, mostly representing light and medium renovations. Using the average of 1.25% between 2018 and 2030, this will require a renovation rate of 3.25% per year between 2030 and 2050, with a much higher share of deep renovations. It would require an extraordinary effort to grow from this 1.25% rate to 3.25% within a couple of years. This will be a near impossible task under current conditions and policies. Assuming such efforts will not be realised under current EU policies, an extrapolation is made from the current situation to 2050.

100 Heat Roadmap Europe, 2018. Baseline scenario of the total energy system up to 2050, page 8. Available at: https://heatroadmap.eu/wp-content/uploads/2018/11/HRE4_D5.2.pdf.

101 Ipsos and Navigant, 2019. Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU, page 15. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/1.final_report.pdf.

Figure 15. Development of share of buildings renovated in the Current EU Trends Pathway



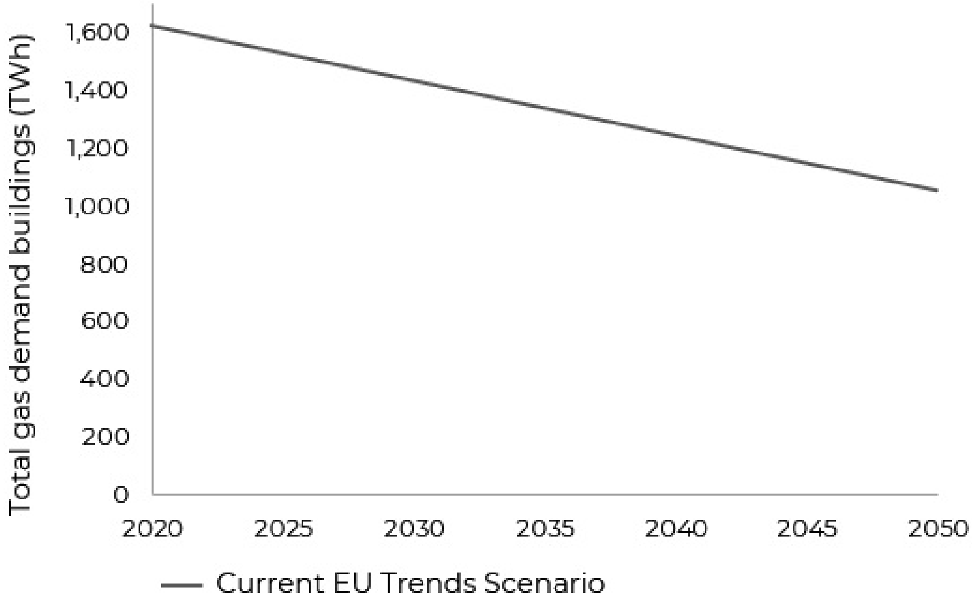
Source: Guidehouse

The renovation rates and depth of renovations in this scenario will not be high enough to get to the Gas for Climate Optimised Gas end state. The lack of proper heat demand reduction throughout the built environment will prevent heat pumps (which require low temperature heating distribution) to be applied to the full extent. This will result in a relatively low reduction of heat demand and a relatively low application of hybrid heat pumps.

Based on data from Heat Roadmap EU[102] and a small reduction towards 2020, energy use of gas in buildings is about 1,600 TWh in 2020. Assuming Current EU Trends will not significantly alter our current (primary) energy savings rate of 1% per year, there will still be a gas demand of around 1,100 TWh towards 2050. Hybrid heat pumps fed with biomethane could cover an increasing share towards 2050, but a full phaseout of fossil gas seems unlikely in this scenario due to the relatively limited share of energy reduction in the built environment. Hybrid heat pumps fed with biomethane could cover an increasing share towards 2050, but a full phaseout of natural gas seems unlikely in this scenario due to the relatively limited share of energy reduction in the built environment

102 Based on data from heatroadmaps.eu, available at: https://heatroadmap.eu/wp-content/uploads/2018/09/HRE4-Exchange-Template-WP3_v22b_website.xlsx and internal analysis.

Figure 16. Development of total gas demand [in TWh] for heating in buildings in the Current EU Trends Pathway



Source: Guidehouse

3.3 Accelerated Decarbonisation Pathway – Buildings

Conclusion Accelerated Decarbonisation

The Accelerated Decarbonisation Pathway envisions a significant increase in energy renovation rates towards 2030 (to between 2.5% and 3% per year) to reach net-zero emissions, as in the Gas for Climate 2050 Optimised Gas end state. Focused policies such as long-term renovation targets and increasing required minimal energy performance levels of existing buildings could help reach this challenging goal. In addition, increasing knowledge build-up around low carbon buildings, reducing hassles for building owners, and supporting financing options are required to create the right environment. A more focused push to switch to low carbon heating technologies in well-insulated buildings is necessary to get to the right pathway.

Current gas used for heating and hot domestic water is about 1,600 TWh (almost all natural gas), which would reduce towards around 1,300 TWh in 2030 before reaching the Gas for Climate Optimised Gas end state of 400 TWh biomethane and (a small share of) hydrogen in 2050, all in hybrid heat pumps by then.

3.3.1 Implications of the European Green Deal for buildings

The European Commission's strategy, A Clean Planet for All,[103] acknowledges that almost the full building stock requires renovation to meet the 2050 targets. The communication on the European Green Deal of December 2019[104] indicates a more focused and rigorous approach to energy efficiency and renewable energy production in the built environment, although details and specific legislation and actions are still to be defined.

A rigorous and successful approach to decarbonise the EU building stock should aim to lift the barriers as discussed in the previous section: the low renovation rate and insufficient renovation depth of the EU building stock. A comprehensive policy design and implementation should also address societal barriers:[105]

- (Perceived) lack of business case or benefit from energy renovations
- Too expensive or difficult to finance
- Lack of knowledge and information at stakeholders
- Administrative/regulatory barriers
- Unavailability of installers

3.3.2 Pathway towards the 2050 Optimised Gas end state

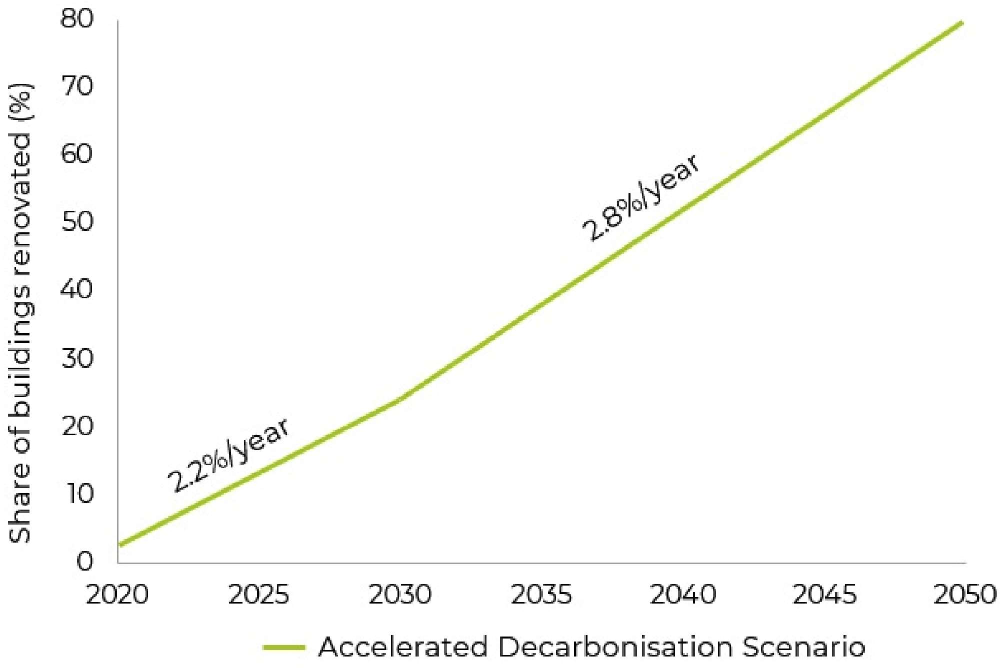
With additional policy measures focused on the three key points (increased renovation speed, improved depth of renovation, and organising step-by-step decarbonisation renovations), it should be possible to significantly increase renovation efforts throughout Europe. Assuming growth of the renovation rate towards 2.8% per year (from the current 1% to 1.5%), the average renovation rate between 2018 and 2030 could be around 2.2% (the average depth of energy renovations needs to increase at the same time). Even with focused, comprehensive, and extensive policies this will be a challenging task, requiring roughly a doubling of the current renovation market. It will require continued efforts to keep this renovation rate constant at 2.8% per year, especially towards 2050 when it is likely the most complicated buildings will have to be renovated.

103 European Commission 2018. In-depth analysis in support of the commission communication, page 90. Available at: https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf.

104 European Commission, 2019, Communication from the commission to the European Parliament, the European Council, The Council, The European Economic and Social Committee and the Committee of the Regions, page 9-10. Available at: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

105 Ipsos & Navigant, 2019. Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU, pages 56-62. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/1.final_report.pdf.

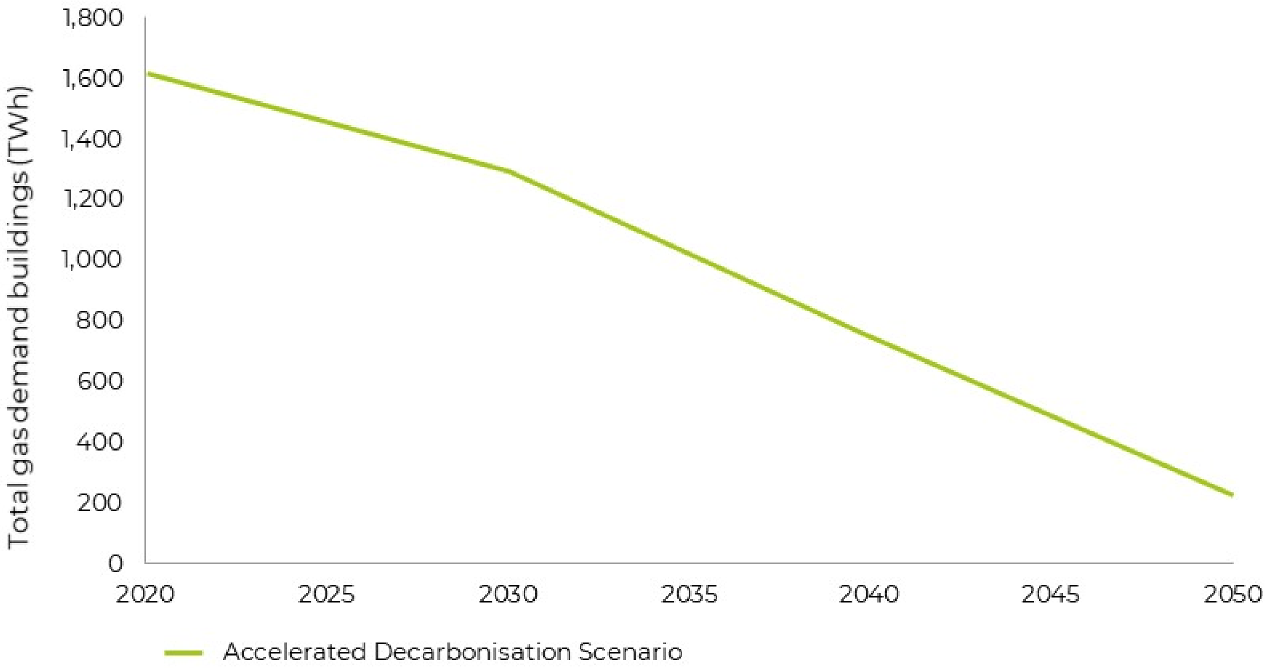
Figure 17. Development of share of buildings renovated in Accelerated Decarbonisation Pathway to reach the Gas for Climate 2050 Optimised Gas end state



Source: Guidehouse

Assuming the new European Green Deal adopts comprehensive and far-reaching policies along the lines of the recommendations made above, it is estimated that energy savings in the built environment should significantly increase towards and beyond 2030. If the primary energy savings increase from the current 1% per year towards 1.5% to 2% per year, this will result in a total gas demand of about 1,300 TWh–1,400 TWh per year (from the current ~1,600 TWh). After an initial ramp-up of the hybrid heat pump market towards 2030, it is likely they only cover a small share of gas demand in buildings. However, especially between 2030 and 2050, it is expected that hybrid heat pump applications could cover the full (leftover) gas demand in the built environment under the assumed policies.

Figure 18. Development of total gas demand [in TWh] for heating in buildings in Accelerated Decarbonisation Pathway



Source: Guidehouse

3.3.3 Critical timeline

The Accelerated Decarbonisation Pathway envisions an increase in energy renovation rates to 2.5%-3% per year, at deep renovation levels, towards 2030. Only then it is possible to achieve a fully decarbonised built environment by 2050. Gas demand for heating and hot domestic water is currently about 1,600 TWh (almost all natural gas) and this will reduce to around 1,300 TWh in 2030. By 2030, buildings would already receive 5%-10% biomethane on average, in regions with a more rapid scale-up of biomethane this percentage would be higher by 2030. While the share of renewable and low carbon gases will be limited in 2030, developments in the built environment will enable the transition towards a decarbonised gas supply in buildings by 2050. In achieving the higher renovation rates needed, three elements should be addressed: [106]

1. Increase renovation speed of all buildings, with a substantial energy improvement component.
2. Improve the depth of renovation, going from light and medium renovations to medium and deep renovations.
3. Organise decarbonisation renovations as a chain of step-by-step smaller renovations (e.g., light and medium) in individual renovation roadmaps where lost opportunities and lock-in effects are avoided.

This will require extensive policy support and the development of new approaches to speed innovation, reduce cost, and make energy renovations a more logical go-to option for building owners, especially in the next 5 to 10 years (Figure 19).

A specific policy example to address the first two abovementioned points can be found in the Dutch Climate Agreement, a programme called the Renovation Accelerator has been detailed to achieve these goals.[107] There are several ways in which policies, regulation, and targets can be used to support a significant short-term increase in renovation rate and depth. For example:

- Create strong and binding long-term renovation targets.
- Support build-up in expertise, knowledge dissipation, and policy support for further development of the renovation market.
- Phaseout newly installed fossil-only heating systems towards 2040.

106 Ipsos and Navigant, 2019. Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU, pages 79-80. Available at: https://ec.europa.eu/energy/sites/ener/files/documents/1.final_report.pdf.

107 Klimaatakkoord, 2019. Klimaatakkoord, 'Renovatieversneller' mentioned multiple times in pages 19-34. Available at: https://www.klimaatakkoord.nl/klimaatakkoord/documenten/publicaties/2019/06/28/klimaatakkoord.

- Focus on soft non-technical factors such as improving health, reducing hassles for building owners, and improving building quality and looks.
- Embed these measures in a comprehensive approach to focus on decarbonisation such as increasing CO_2 prices or trading mechanics, increasing availability of low rent long-term green loans, and supporting taxation and subsidy schemes.

Start a renovation wave

Decarbonising the built environment affects a broad variety of stakeholders. Private house owners, building corporations, and commercial real estate owners need to invest in increasing the building stock's energy efficiency. Local governments need to provide the vision and strategy on how areas should develop. Energy distribution companies and energy companies could play an organising and facilitating role in this as well. For serialised scale-up of renovation by housing corporations and commercial real estate owners, it is key that the building industry realises industrial innovation and standardisation to drive cost reduction. Extensive energy efficiency measures are best timed at natural investment moments, such as a change in building owners or tenants, or when investments in the building energy system are necessary. The energy and buildings industry need to offer approaches to unburden building owners through standardised solutions, renovation roadmaps, guarantees, and financing options.

Long-term renovation targets and increasing the required minimal energy performance levels of existing buildings are examples of focused policies that could help buildings reach higher renovation rates. One of the EU Green Deal's objectives is to start a renovation wave. An example of a policy that addresses the elements above is the Renovation Accelerator as included in the Dutch Climate Agreement.[108]

Increasing knowledge around low carbon buildings, reducing hassle for building owners, and supporting financing options are required to create the right environment. A more focused push to switch to low carbon heating technologies in well-insulated buildings is necessary to get to the right pathway. The full renovation system must be in place and doing the right renovation at high enough renovation rates by 2030.

Deployment of hybrid heating solutions

In addition to improving buildings' energy efficiency, a transition towards low carbon heating technologies is needed. Technology providers need to make sure that low carbon technologies, including hybrid heat pumps, are developed and offered in a structured way. Building owners can then move to low carbon heating technologies at natural replacement moments. While building renovation is a good time to implement low carbon heating technologies, full alignment is not critical. When building renovation is planned for a later date, hybrid heating solutions can be applied to decarbonise the heating system. Such a transition pathway can look as follows:

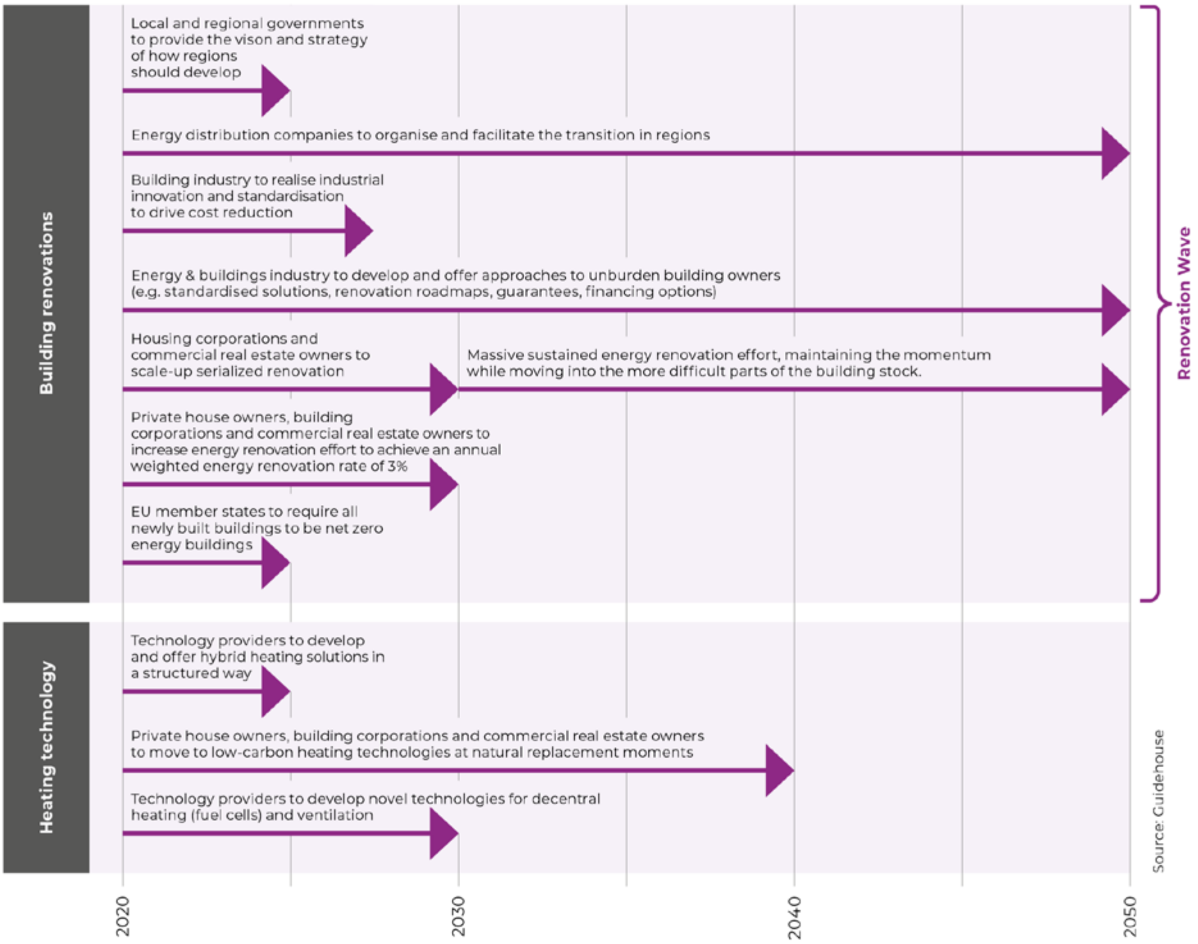
- Per building, a modest electric heat pump is added to the existing gas-fired boiler, with a smart control to make the combination a hybrid heat pump.

- As the home becomes better insulated, the electric heat pump takes up a higher share of the heating, and the ratio between gas and electricity shifts.

As the share of biomethane and hydrogen in the gas distribution grid increases, gas is increasingly decarbonised. As the share of renewables in the electricity distribution grid increases, electricity is greened.

108 Klimaatakkoord, 2019. Klimaatakkoord, 'Renovatieversneller' mentioned multiple times in pages 19-34. Available at: https://www.klimaatakkoord.nl/klimaatakkoord/documenten/publicaties/2019/06/28/klimaatakkoord.

Figure 19. Critical timeline buildings



What if the Green Deal cannot deliver the required building renovation rates?

As discussed in this chapter, the additional policies, measures, and changes to the construction sector are extensive and impactful. It is possible that even with a lot of additional efforts, the objectives of increases to renovation rates and heat pump applications could not be reached. To ensure full decarbonisation of the EU building stock, it will be important to keep possible alternatives in mind: renewable heat supplied through a range of renewable heating technologies. For example, gas heat pumps or hydrogen fuel cells or boilers could be applied in specific situations where (hybrid) heat pump application is difficult. These technologies could also be applied in combination with limited insulation, although this will put additional pressure on the availability of low carbon renewable gases.

3.3.4 Policy recommendations

Apply 100mln hybrid heating solutions in renovated older buildings

The Accelerated Decarbonisation Pathway leads to a situation in which all European buildings will be well-insulated in the period 2020 to 2050 and older buildings with gas grid connections will be heated through hybrid heating technology, which is a combination of a small electric heat pump and a small gas boiler. Such a pathway yields considerable societal cost benefits that result from preventing that the whole building stock should undergo very deep renovations, using existing gas distribution infrastructure and minimising peaks in heating energy while reducing overall energy demand through insulation. However, this can only be implemented if hybrid heating technologies are promoted and if the speed and intensity of building renovation is dramatically increased.

The main EU policies that drive decarbonisation in the EU buildings stock (EPBD, EED, and LTRS) fall short in delivering the necessary renovation speed. Today, limited incentives for hybrid heating solutions exist.[109] In policy studies and scenarios, the option is often overlooked: by 2050, buildings are assumed to be heated either with (all-)electric heat pumps or by district heating or using renewable gas. Consumers are largely unaware of the option of hybrid heating, and installers have insufficient knowledge of how to change an existing gas-fired heating system into a hybrid one.

The following policy changes should be considered as part of the EU Green Deal:

1. Set ambitious binding targets for energy renovations of buildings, both in terms of the depth of renovations and the speed of their implementation in member states. These targets should create a renovation wave that drives the improvement of buildings' energy performance.

2. Take up the option of hybrid heating systems in policy studies, scenarios, and in plans for the announced Renovation Wave.

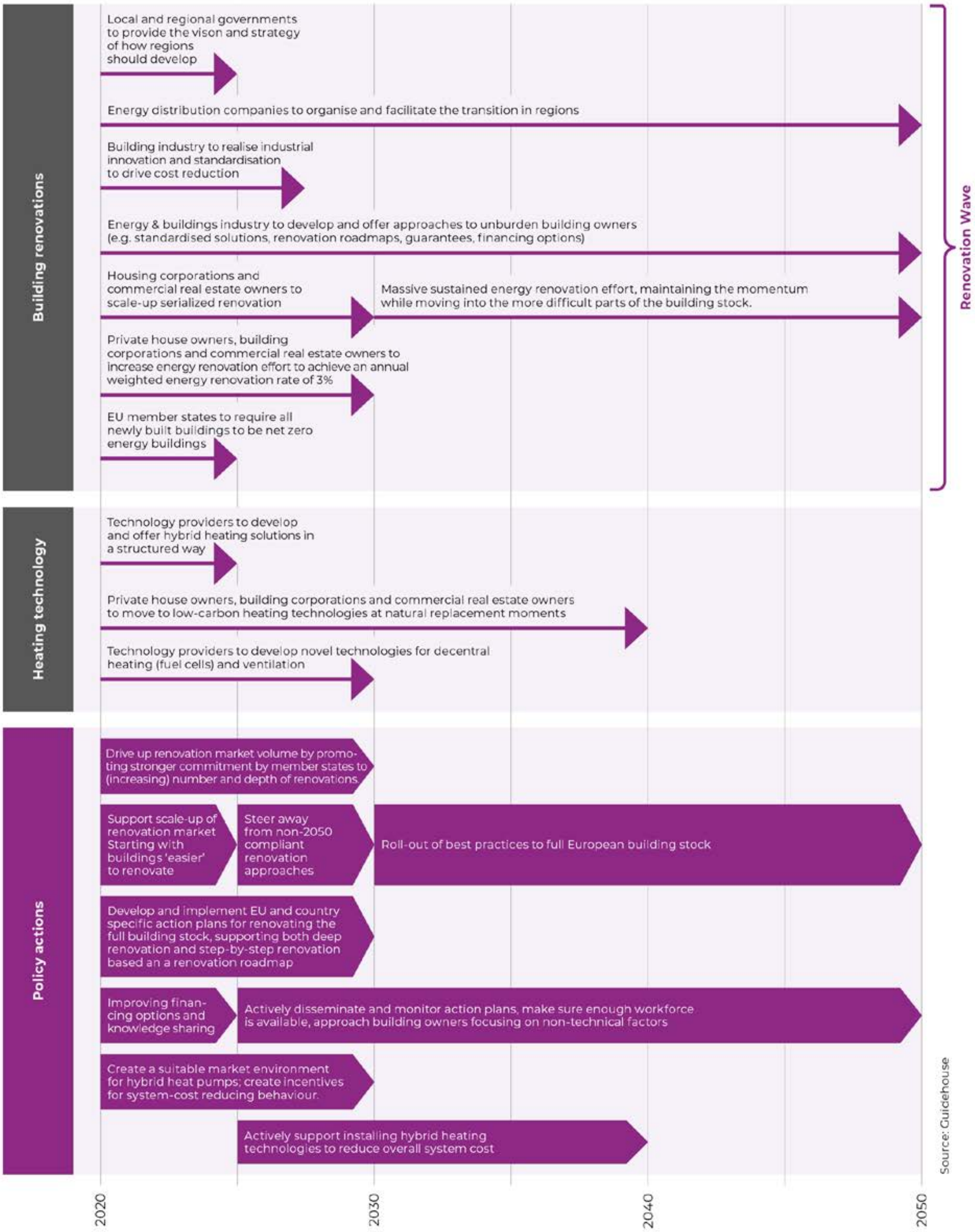
3. Foster increased awareness of hybrid heating systems through EU political support and by programmes initiated by member states, installers, and consumers.

4. Create a sustainable market environment for hybrid heating systems, and

Actively propagate the installation of hybrid heat pumps in older buildings that have gas connections today.

109 An example is a subsidy of €800 in Flanders, Belgium (https://www.vlaanderen.be/premie-van-de-netbeheerder-voor-een-warmtepomp) and €1,500-€1,800 in the Netherlands (https://www.milieucentraal.nl/energie-besparen/energiezuinig-huis/financiering-energie-besparen/subsidie-warmtepompen/).

Figure 20. Critical timeline and policy actions for buildings



3.4 Global Climate Action Pathway

Conclusion Global Climate Action

The Global Climate Action Pathway indicates that significant cost reductions to insulation and heating technologies could speed up the renovation process by opening the possibility to perform significant energy renovations outside of normal renovation cycles. In addition, faster, more convenient renovations and a wider range of renovation options enables a faster scale-up towards net-zero emissions, as in the Gas for Climate 2050 Optimised Gas end state.

The current natural gas for heating and hot domestic water of about 1,600 TWh will reduce towards around 1,200 TWh in 2030 under these assumptions, and the Gas for Climate end vision of 400 TWh in 2050. The share of gas use for hybrid heat pumps will be limited, but all gas use in 2050 is expected to be for hybrid heat pumps.

3.4.1 Expected technological and cost developments

The basic components of a deep energy renovation are already widely available in the market: insulation materials and heat pumps have been implemented for years in many buildings. However, applying these two components at a significantly higher implementation speed will be crucial. In this scenario, we assumed several technology developments could provide solutions to further decarbonise the buildings sector:

- **More standardising of renovations:** Serialised renovations or industrial renovations where whole streets of similar houses are renovated at the same time.
- **Involvement of pre-fabrication industry:** In this industry, components are made on-demand and site-specific to improve the renovation time. This can significantly reduce labour requirements, which means companies can renovate more buildings.[110]
- **The establishment of companies that work as process leaders:** These companies will reduce the hassle for building owners by proposing a plan, taking care of selecting providers, and financing and making sure planning and quality are in order.
- **Improvements in heat pump technology:** Improvements include soundwave-based heat pumps or room-specific air-to-air installations including ventilation. Another possibility is a combination of heat pumps with infrared heating for rarely used rooms.

Like technology developments, global action can also affect costs for insulation materials, heat pumps and standardised (serial/industrial) renovations. It is likely that significant price developments could speed the process of renovation by providing a more compelling business case. New insulation materials, heat distribution technologies, and non-material price reductions (e.g. more efficient installation) could provide for cost reductions. Such cost reductions can increase the energetic component of regular renovations and could even provide the possibility of deeper renovations outside of normal renovation cycles.

Many of the elements listed above are developments that also occur as part of the Accelerated Decarbonisation Pathway, yet global action and sharing of best practices may lead to better, cheaper solutions.

3.4.2 Pathway towards 2050

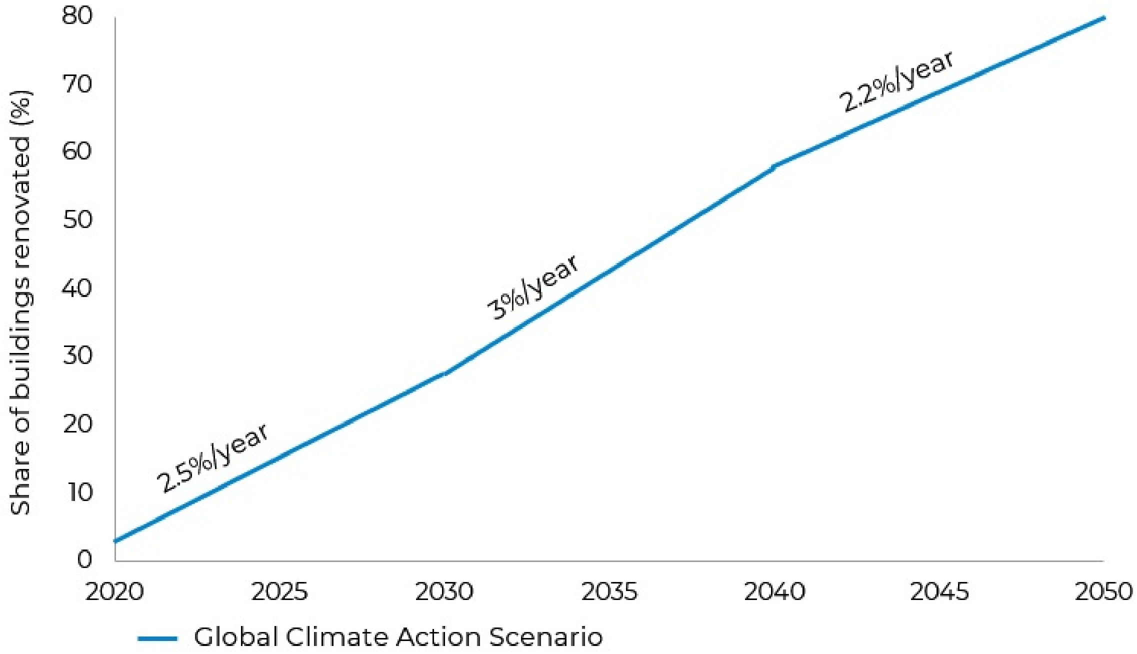
Rapid improvements for industrialised renovations and significant cost reductions in heat pump technology and insulation could kick-start low carbon renovations in the short term. Especially for countries that have significant shares of buildings

110 ING, 2018. [Dutch] ConTech: Technologie in de bouw. Bouw digitaliseert volop maar industrialiseert nauwelijks. Available at: https://www.ing.nl/media/ING_EBZ_ConTech_Bouw-digitaliseert-volop-maar-industrialiseert-nauwelijks_Nov-2018_tcm162-157771.pdf.

with similar characteristics, this could provide for a fast implementation towards 2030-2040. Between 2040 and 2050 this would leave the (much) more difficult buildings to be retrofitted, lowering renovation rates.

If a renovation rate of 2.5% on average is expected towards 2030 and a rate of 3% is expected from 2030 to 2040, this would leave a 2% renovation rate from 2040 to 2050 for the more difficult buildings (e.g. monuments). These renovation rates are considered high and would require a much more efficient renovations to the building stock to be achievable.

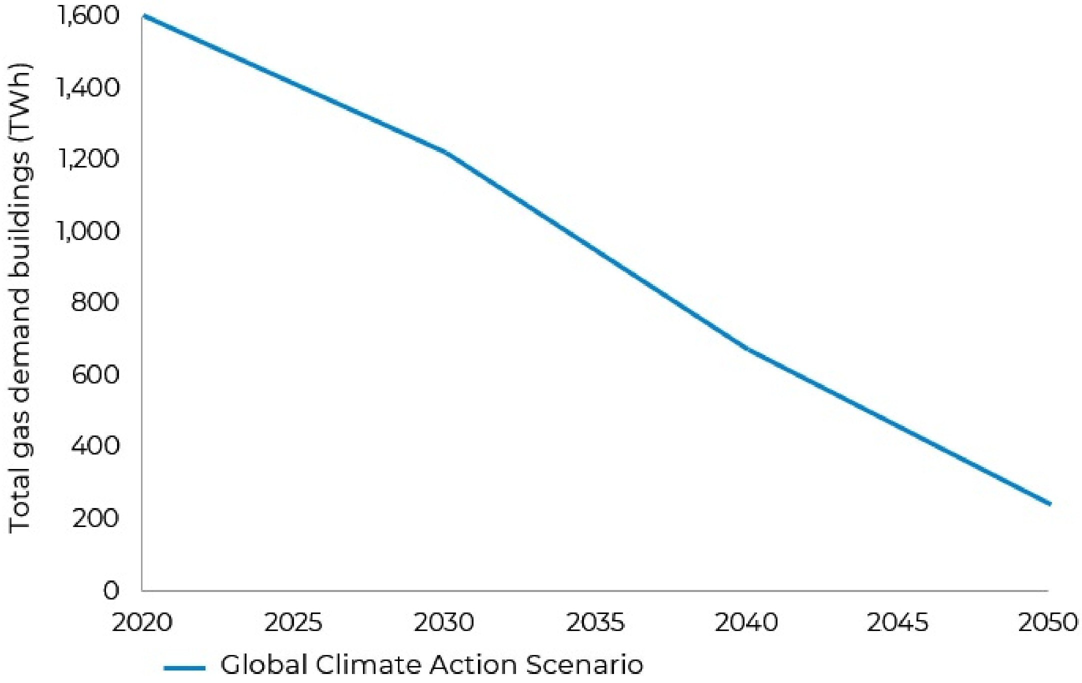
Figure 21. Development of share of buildings renovated in the Global Climate Action Pathway.



Source: Guidehouse

If the global market pushes for new technologies and significant cost reductions, it could result in a significant increase in energy savings in the built environment towards 2030. Assuming the energy savings are about 2% per year between 2020 and 2030 (from the current 1% per year), this would reduce the energy demand in the built environment below 1,300 TWh in 2030. Following the market ramp-up of new technologies and approaches a push towards more efficient buildings is expected between 2030 and 2040. Under the previously mentioned assumptions, a fully decarbonised building sector should be possible towards 2050. The share of hybrid heat pumps initially will be limited, but from 2030 to 2050 the full roll out of this technology could be present.

Figure 22. Development of total gas demand for heating in buildings in the Global Climate Action Pathway



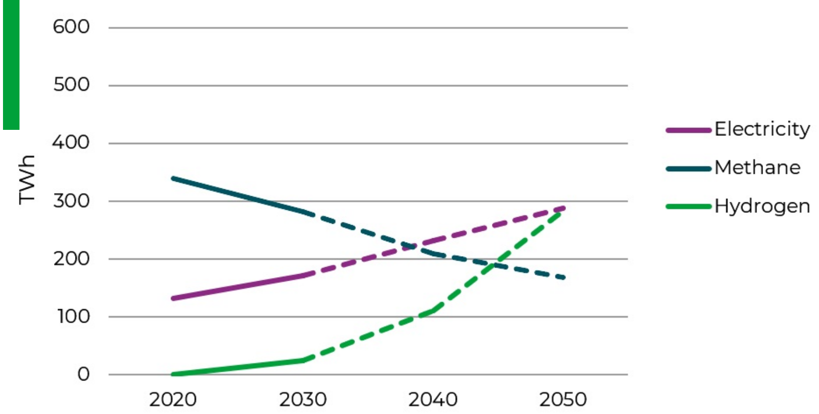
Source: Guidehouse

4. Industry Decarbonisation Pathways

Key Takeaways

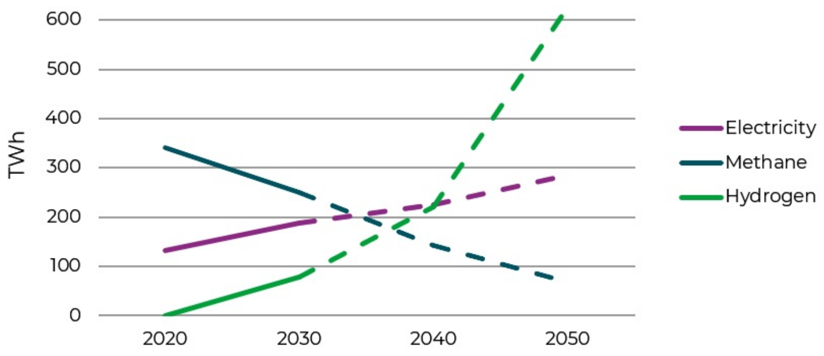
- The Gas for Climate 2050 end state is extremely difficult to reach under the Current EU Trends Pathway. Investments in breakthrough technologies will likely be postponed due to the lack of a supporting regulatory framework or go into conventional technologies, creating long-term lock-in effects. The uptake of renewable and low carbon gases is limited to around 25 TWh-35 TWh in 2030.
- A more ambitious Accelerated Decarbonisation Pathway would result in a carbon price that allows for investments in breakthrough technologies. Biomethane would partly replace natural gas in the 2020s. First large-scale hydrogen applications in steel and ammonia production would be initiated towards the end of the 2020s. The demand for renewable and low carbon gas would increase to 70 TWh-100 TWh in 2030.
- Global climate action supported by a global carbon price of €55/t CO_2 by 2030 would lead to the rapid phaseout of fossil fuels, including natural gas. Biomethane and hydrogen would already make up one-third of final energy consumption in industry by 2030. An international market for synthetic fuels would emerge, partly replacing European hydrogen demand, in particular for methanol.

Figure 23. Energy demand in industry, Current EU Trends Pathway



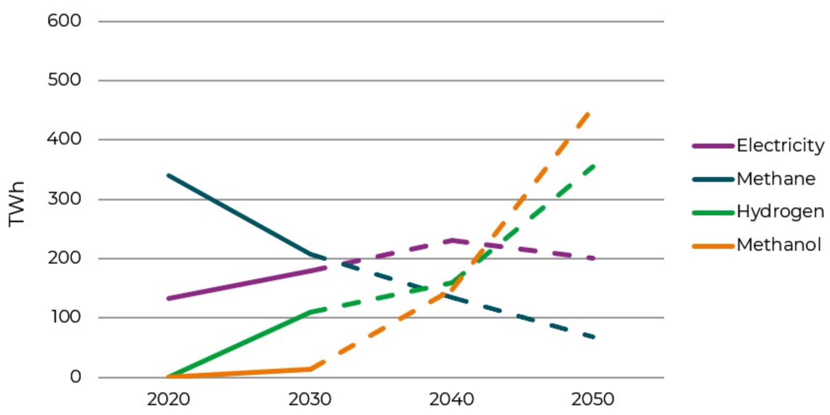
Source: Guidehouse analysis

Figure 24. Energy demand in industry, Accelerated Decarbonisation Pathway



Source: Guidehouse analysis

Figure 25. Energy demand in industry, Global Climate Action Pathway



Source: Guidehouse analysis

4.1 Introduction

4.1.1 Current situation

The industry sector is important to the EU economy in terms of added value and job creation. The sector also has a high energy demand and greenhouse gas emissions, despite a strong reduction since 1990. In 2016, industry accounted for 22% (2,650 TWh) of the EU's final energy consumption.

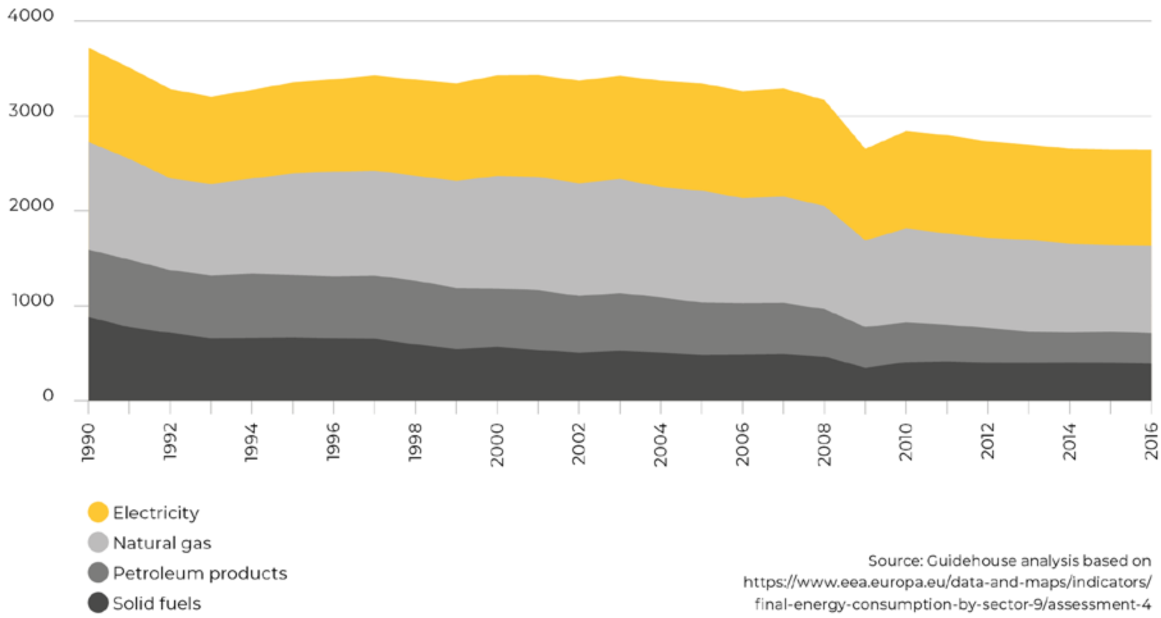
Electricity (1,010 TWh) and natural gas (920 TWh) are the most important energy sources, and their relative share has grown. Thanks to improved process efficiency and a shift to lower emission energy sources, in combination with displacement of some industrial production to other continents, industrial greenhouse gas emissions decreased strongly, 38% from 1990 to 2016. This decrease was the largest of any other sector.[111] The industry sector currently forms over 90% of the EU hydrogen market with a total consumption in Europe of around 339[112] TWh of hydrogen. Next to refining (153 TWh of hydrogen), the chemical sector has the largest market share, with main uses in ammonia (129 TWh of hydrogen) and methanol (27 TWh of hydrogen). While the industry sector has experienced an overall decline in final energy consumption by 29% from 1990 to

111 European Environment Agency, "GHG emissions by Sector," 2018, https://www.eea.europa.eu/data-and-maps/daviz/ghg-emissions-by-sector-in#tab-chart_1.

112 FCH-JU Hydrogen Roadmap Europe, https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

2016, natural gas consumption declined by 19% and electricity increased by 2% over the same period (Figure 26). As a result, the relative share of electricity and natural gas in final energy consumption of the industry sector increased.[113]

Figure 26. Development of final energy consumption in EU industry sector



Thanks to improved process efficiency and a shift to lower emission energy sources, in combination with displacement of some industrial production to other continents, industrial greenhouse gas emissions decreased strongly, 38% from 1990 to 2016. This decrease was the largest of any other sector.[114]

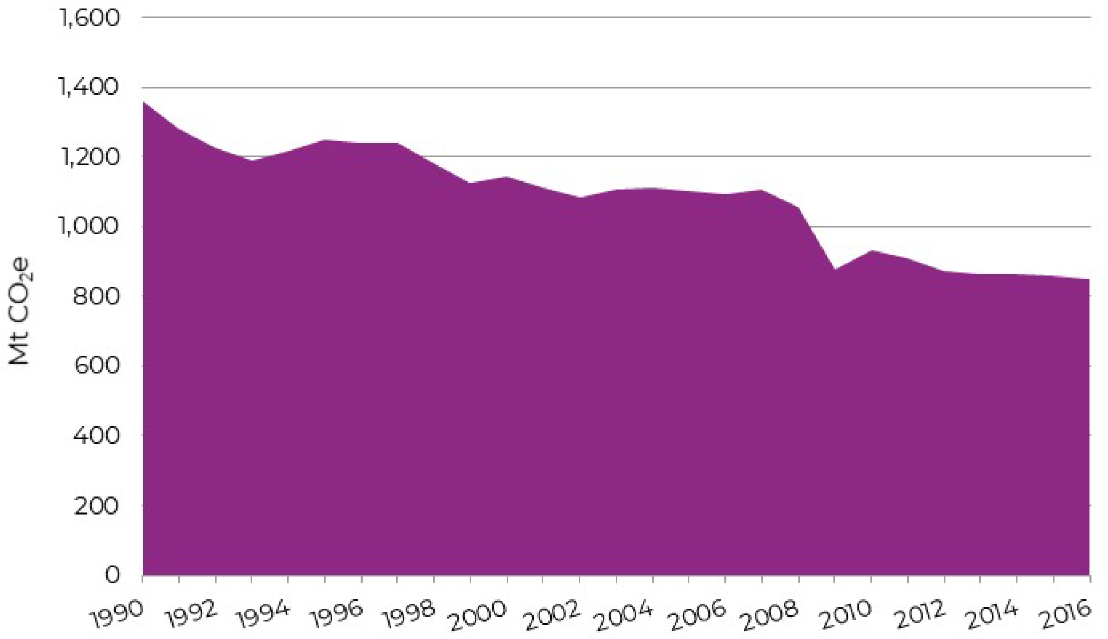
In 2016, the industry sector accounted for 20% of the EU's total greenhouse gas emissions. This includes all scope 1 emissions, i.e. energy- and process-related emissions, and emissions from self-produced electricity. Emissions from purchased electricity or heat and steam are attributed to the power sector. In contrast to the power, transport, or buildings sectors, not all emissions in the industry sector are related to energy that provides heat or to industrial processes. Process emissions (i.e. emissions from industrial processes involving chemical or physical reactions other than combustion) are another major source of industrial greenhouse gas emissions. For example, in the cement industry, process emissions account for two-thirds of total emissions.

Most of the greenhouse gas emissions associated with the industry sector come from natural gas, oil products, and solid fuels (e.g., coal) to provide heat and feedstocks. Feedstocks refer to raw materials fed into a process for conversion into another product.

113 European Environment Agency, "Final Energy Consumption by Sector and Fuel," 2018, https://www.eea.europa.eu/data-and-maps/indicators/final-energy-consumption-by-sector-9/assessment-4.

114 European Environment Agency, "GHG emissions by Sector," 2018, https://www.eea.europa.eu/data-and-maps/daviz/ghg-emissions-by-sector-in#tab-chart_1.

Figure 27. Development EU greenhouse gas emissions in EU industry sector



Source: https://www.eea.europa.eu/data-and-maps/daviz/ghg-emissions-by-sector-in#tab-chart_1.

Decarbonisation of the industry sector is a challenge, particularly for feedstocks (raw materials fed into a process for conversion into another product) and high temperature processes. When electricity is used for industrial processes, decarbonisation needs to happen in the power sector. Additional electrification potential exists for low to medium temperature heat processes. Temperature levels below 150°C can be decarbonised by geothermal energy, heat pumps, solar thermal energy, or direct electrification. Electrification of high temperature industrial heat, although possible, is more challenging. Other decarbonisation options using low carbon gases are needed like the direct reduction of iron ore (DRI) using hydrogen or using methanol to produce high value chemicals. However, such technologies are often (at least initially) characterised by higher costs, which could result in a loss of international competitiveness in the European industry. The right regulatory framework is needed for energy-intensive industries to start investing in breakthrough technologies. If this does not occur, companies will continue to invest in conventional technologies. Since investment cycles in industry often exceed 30 years, investments in conventional technologies can create lock-in effects and the risk of stranded assets.

As in the Gas for Climate 2050 study published in 2019, the analysis below focuses on the most emissions-intensive and hard to decarbonise industry sectors: chemicals (production of ammonia and high value chemicals), iron and steel, and cement. Those three sectors represent just over half of industrial greenhouse gas emissions in Europe.

4.1.2 Gas for Climate 2050 Optimised Gas end state

The Gas for Climate 2019 study concluded that biomethane, green and blue hydrogen and carbon capture storage/utilisation (CCS/CCU) play a central role in reducing emissions in the chemical, steel, and cement industry. Hydrogen is key to reducing emissions from ammonia and high value chemical (HVC) production in the chemical industry. While the ammonia production process will stay largely unchanged and use renewable hydrogen as feedstock instead of grey hydrogen, the HVC production will largely shift from steam cracking to the methanol-to-olefins (MTO) route. In the steel sector, the blast furnace process for primary steelmaking will be replaced by innovative, low carbon steelmaking technologies based on carbon capture and low carbon gases. Secondary steelmaking will also play a bigger role in 2050, meeting 50% of the steel demand in 2050. The cement industry will reduce its process emissions by applying carbon capture and reduce its energy-related emissions by switching from fossil fuels to solid biomass.

4.2 Industry pathway under current EU climate and energy policies

Conclusion Current EU Trends

There will be limited decarbonisation efforts up until 2030 under the Current EU Trends Pathway. The focus is on improved energy efficiency of existing processes to meet the current 2030 greenhouse gas reduction targets. We project a slow uptake in renewable gases in 2020-2030 (around 25-35 TWh) and the postponement of investments in breakthrough technologies until after 2030, missing the major natural replacement moments occurring in this decade. Alternatively, investments may be made in conventional technologies, causing the risk for long-term lock-ins and stranded assets. Hence, the Gas for Climate 2050 Optimised Gas end state is unlikely to be reached under the Current EU Trends Pathway.

4.2.1 EU policies

Current policies are aligned under the EU 2030 Climate and Energy framework, which sets the target to cut greenhouse gas emissions by at least 40% in 2030 compared to 1990 levels. The revised framework also aims to increase the share of renewable energy to at least 32% and achieve an energy efficiency improvement of at least 32.5% by 2030.

EU ETS is a cornerstone of the EU's policy to combat climate change and is the key tool for reducing greenhouse gas emissions in the industry sector. It was the world's first major carbon market and remains the biggest. The system operates in all EU countries, in addition to Iceland, Liechtenstein, and Norway. It limits emissions from more than 11,000 heavy energy-using installations (power stations and industrial plants) and airlines operating between these countries. The system covers around 45% of the EU's greenhouse gas emissions, and the EU ETS sectors will have to cut emissions by 43% in 2030 (compared to 2005). The EU ETS also provides revenue to the world’s largest funding programme for demonstration of innovative low carbon technologies—the EU Innovation Fund. Depending on the carbon price, the fund may amount to about €10 billion until 2030, to support innovation for energy-intensive industry, renewables, energy storage, and CCS/CCU.

Under the EU ETS, the price of CO_2 has quadrupled in the past 3 years from around €5/tCO_2 to more than €20/t CO_2.[115] This increase is mainly caused by the overhaul of the EU ETS Directive for the years 2021-2030, which has already resulted in a reduction in the number of CO_2 certificates on the market. Higher CO_2 prices increase the production costs for the energy-intensive industry and consequently influence decisions on investing in breakthrough technologies. In the Current EU Trends Pathway, we use a moderate price increase reaching €35/t CO_2 in 2030.[116]

Other EU policies that substantially impact the industry sector include the 2017 industry strategy and the 2015 action plan on circular economy. In September 2017, the European Commission adopted its communication on *Investing in a Smart, Innovative and Sustainable Industry – An Industrial Strategy for Europe*. This outlined the main priorities and key actions for strengthening Europe's industrial base, including: a deeper and fairer single market, upgrading industry for the digital age, building on Europe's leadership in a low carbon and circular economy, investing in infrastructure and new technologies to drive industrial transformation, supporting industrial innovation on the ground, promoting open and rules-based trade, and empowering regions and cities to address challenges. The *EU Action Plan for the Circular Economy*, published in 2015, aims to stimulate Europe's transition towards a circular economy, boost global competitiveness, foster sustainable economic growth, and generate new jobs.

4.2.2 Regional differences

Industry is typically organised in clusters, resulting in industrial sites being concentrated in specific geographies across Europe. Germany is the main industrial centre in the EU; other countries with a significant industry sector include Italy, the Netherlands, Spain, and France. While the previously mentioned EU policies affect industry regardless of location, member

115 Sandbag, “Carbon Price Viewer”, https://sandbag.org.uk/carbon-price-viewer/.
116 In line with the EU CO2 price in IEA’s WEO 2019

states also have implemented policies to reduce energy consumption in and greenhouse gas emissions from the industry sector. Germany and the Netherlands have specific strategies on the role of hydrogen.

Germany

Germany accounts for 26% of crude steel production and 29% of EU chemical sales.[117, 118] In 2018, the German industry sector was responsible for 196 million tonnes of greenhouse gas emissions (one-quarter of total greenhouse gas emissions in Germany), down from 284 million tonnes in 1990.[119] In December 2019, the government adopted a climate policy package (Klimaschutzprogramm 2030) to meet its 2030 targets. For the industry sector, the programme focuses on energy efficiency, resource efficiency and substitution, and the use of renewable fuels for process heat. It also includes financial aid for demonstration projects of breakthrough technologies.

The German government began drafting its national hydrogen strategy in 2019. Reports suggest that the use of hydrogen will be prioritised in sectors with limited alternative options for decarbonisation (such as steel and chemicals). Levies for electricity should also change to allow for the cheaper production of green hydrogen. The draft strategy is reported to aim for the integration of electricity, heat, and gas infrastructure, the use of existing infrastructure for hydrogen transport, and energy partnerships with EU and non-EU countries.

The Netherlands

The Netherlands accounts for 4% of EU steel production and 10% of chemical sales. In June 2019, the Dutch government published its *Climate Agreement*, which details how the reduction target of 49% greenhouse gas emissions in 2030 (compared to 1990 levels) should be achieved.

For the industry sector, the Dutch Climate Agreement focusses on several elements including a national hydrogen programme, a robust regional cluster approach, the circular economy, and innovation programmes. As part of its national hydrogen programme, the Dutch government wants to accelerate the development of green hydrogen and the hydrogen economy. Hydrogen is seen as the principal decarbonisation solution for reducing process emissions and providing heat above 600°C.

4.2.3 Technological and cost developments

Uncertainty around the long-term investment climate for breakthrough technologies will lead to stagnating industrial research and development in low carbon technologies. As a result, we do not foresee accelerated cost decreases and technological improvements under current EU policies.

4.2.4 Pathway towards 2050

In the Current EU Trends Pathway, we expect limited investments in breakthrough technologies in the coming decade. Due to natural replacement cycles, large investments in the chemical, steel, and cement industry are expected from 2020 to 2030. Many of the current installations, such as steam crackers or blast furnaces, are older than 50 years. The current policy framework does not allow for long-term planning and investments in breakthrough technologies (loss of international competitiveness) leaving the industry with three options:

1) Postponing investments into the 2030s
2) Investing in conventional technologies
3) Investing outside of the EU

Option 1 would see the industry sector investing in maintenance of assets that would normally be replaced by new, more efficient ones. This additional maintenance effort would result in additional costs and conflicts with established investment cycles; it entails the risk of the industry leaving the site after the extended lifetime of the assets. Option 2 would eventually lead to lock-in effects or stranded assets given the long-term nature of investments in industrial plants (>30 years, so reaching

117 Eurofer, "European Steel in Figures 2019", http://www.eurofer.org/201907-SteelFigures.pdf?wtd=aZO7VePBb33NWwWF&request=resource&resource=ok3819r&rand=2

118 Cefic, "2020 Facts & Figures of the European chemical industry", https://cefic.org/app/uploads/2019/01/The-European-Chemical-Industry-Facts-And-Figures-2020.pdf

119 Umwelt Bundesamt, "Germany's Climate Protection Goals," May 6, 2019 https://www.umweltbundesamt.de/daten/klima/klimaschutzziele-deutschlands.

beyond 2050). In option 3, regulatory uncertainty would negatively impact long-term planning security. Hence, investments in new technologies that increase demand for low carbon or renewable gases may be carried out outside of Europe.

As a result, the demand for renewable and low carbon gases in 2030 will only be around 25-35 TWh[120]. This demand is derived from first renewable gas applications in ammonia production and blending of biomethane or hydrogen with natural gas in the direct reduction of iron ore, provided there would be dedicated financial support for this, since the CO_2 price is insufficient in the cement sector, only few sites will apply CCS/CCU. Production of low carbon methanol will only be around 2.1 Mt in 2030 (compared to 74.1 Mt in the Gas for Climate 2050 end state) resulting in limited renewable hydrogen demand.

In the remaining industry, the focus will be on improving energy efficiency to reduced energy costs and regulatory costs (e.g., CO_2 prices). Electrification of low to medium temperature process and the use of renewable and low carbon gases will only play a minor role.

Given the above, the Gas for Climate 2050 end state is unlikely to be reached under the Current EU Trends Pathway.

4.3 Accelerated Decarbonisation Pathway – Industry

Conclusion Accelerated Decarbonisation

In the Accelerated Decarbonisation Pathway, an EU Green Deal, higher CO_2 prices, and the availability of affordable renewable and low carbon gases in the 2020s will accelerate industrial decarbonisation. We expect around 70-100 TWh of demand in renewable and low carbon gases by 2030. In the mid-2020s, the steel industry will start investing in low carbon steelmaking technologies. The cement industry will implement carbon capture and increase the share of biomass. First large-scale applications of breakthrough technologies will be realised by the end of the 2020s. A large demand for renewable and low carbon hydrogen will arise from ammonia production. Following 2030, the demand will further increase as steam cracking (to produce HVCs) is gradually replaced by the low carbon MTO[121] process. Substantial decarbonisation efforts are still needed post 2030; however, reaching the Gas for Climate 2050 Optimised Gas end state with around 700 TWh of renewable gas is plausible.

4.3.1 Implication of the EU Green Deal for industry

The Accelerated Decarbonisation Pathway assumes that European Green Deal will upwardly revise the greenhouse gas emission reduction target of 40% by 2030 to a more ambitious target of 55%. It can be expected that the EU ETS will become more stringent as a result of this more ambitious climate target. Smaller industrial plants not yet covered by the EU ETS may be included after revising the current legislation in 2025. A strengthening of the EU ETS to achieve 55% emission reduction by 2030 may result in an increased CO_2 price of €55/tonne in 2030 and a high share of renewables in the energy system.[122]

The EU Green Deal includes an EU industrial strategy to be adopted by the European Commission in March 2020. In its Communication on the EU Green Deal, the European Commission wrote: “EU industry needs ‘climate and resource front-runners’ to develop the first commercial applications of breakthrough technologies in key industrial sectors by 2030. Priority areas include clean hydrogen, fuel cells and other alternative fuels, energy storage, and carbon capture, storage and

120 The 25-35TWh reflects externally sourced low-carbon gases only. It does not include on-site production of blue hydrogen in industry. In that case, natural gas is the energy carrier sourced by the industry.

121 MTO (methanol-to-olefins) is a low carbon production of high value chemical alternative to conventional steam cracking. Hydrogen and CO_2 is used to produce methanol. In the last process step, methanol is synthesised to propylene or ethylene using electricity and steam.

122 Carbon Tracker, 2018, “Carbon Clampdown: Closing the Gap to a Paris-compliant EU-ETS. Available at: https://www.carbontracker.org/reports/carbon-clampdown/

utilisation. As an example, the Commission will support clean steel breakthrough technologies leading to a zero-carbon steel making process by 2030 [..]."[123]

The Green Deal will also encompass a new Circular Economy Action Plan.[124] It is also expected to expand the EU ETS Innovation Fund and to initiate a new eco-design working plan. These measures will lead to faster decarbonisation towards 2030.

4.3.2 Technological and cost developments

More ambitious energy and climate policies and an increased CO_2 price will accelerate research and development in breakthrough technologies across industry sectors. Consequently, such technologies will mature quicker entering the market at an early stage resulting in a higher demand for low carbon gases. A growing market for low carbon gases will create incentives for investments on the energy supply side bringing down the costs of low carbon gases due to economies of scale.

4.3.3 Pathway towards the 2050 Optimised Gas end state

In the Accelerated Decarbonisation Pathway, higher CO_2 prices and the increasing availability of affordable renewable and low carbon gases in the 2020s will result in faster industrial decarbonisation. Under the EU Green Deal, the implementation of breakthrough technologies in industry will accelerate, resulting in an increased demand of around 70 TWh–100 TWh of renewable and low carbon gases by 2030. By the mid-2020s, industrial companies and research institutes will have made significant efforts to develop breakthrough technologies and bring them to market. We assume that the EU ETS Innovation Fund may subsidise pilot tests and first-of-a-kind plants for low carbon steelmaking and CCS in cement. Higher OPEX from renewable and low carbon gases, critical inputs for low carbon methanol, ammonia, and steel may be partly compensated by policy instruments such as carbon Contracts for Difference (CfDs).[125]

Switching from blast furnaces to low carbon steelmaking processes (e.g. iron bath reactor smelting reduction), processes in combination with CCS, or direct reduction of iron ore with hydrogen or biomethane would significantly increase demand in renewable and low carbon gases. Since substantial investments exceeding €100 million per technology installation are required, few existing plants will be replaced by 2030. Most plants will be replaced after 2030. Additional factors limiting earlier deployment of breakthrough technologies are planning, permitting, and construction. Since innovative technology may require more time for the aforementioned implementation steps compared to conventional technologies, governments should aim to speed this up.

Industrial processes that use large amounts of natural gas, such as the production of ammonia, will switch to low carbon alternatives in the early 2020s. The shift to renewable and low carbon gases will occur first in industrial clusters with proximity to supply locations, e.g. in the Netherlands (blue hydrogen, and green hydrogen from North Sea wind power). All existing steam methane reformers will be retrofitted with carbon capture by 2035. Some solitary industrial plants may start using hydrogen produced locally or supplied by dedicated hydrogen pipelines from initial larger green hydrogen production sites.

With the emergence of a comprehensive, pan-European hydrogen infrastructure by 2035-2040, the implementation of breakthrough technologies in the industry sector will accelerate, for example, direct reduction with hydrogen in steelmaking.

The mid-2020s will see the implementation of the first small-scale carbon capture pilots in the cement industry. To realise the decarbonisation of HVC production, steam cracking will gradually be replaced by the low carbon MTO route starting around 2030. The shift to a CCU technology like MTO requires CO_2 as feedstock. The CO_2 will be fossil in the beginning (e.g. from cement production), which will require CO_2 infrastructure. Towards the Gas for Climate 2050 end state, fossil CO_2 will be replaced by biogenic CO_2, or to the extent needed by atmospheric from direct air capture. Additionally, large amounts of hydrogen are needed to produce low carbon methanol. The implementation of breakthrough technologies largely depends on the regulatory framework. Other factors, such as societal acceptance and the build-up of additional infrastructure, must also be considered.

123 EC, Dec 2019, Communication The European Green Deal: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf

124 EU, 6 Jan 2020: New Circular Economy Action Plan – Consultation on the Roadmap open https://circulareconomy.europa.eu/platform/en/news-and-events/all-news/new-circular-economy-action-plan-consultation-roadmap-open

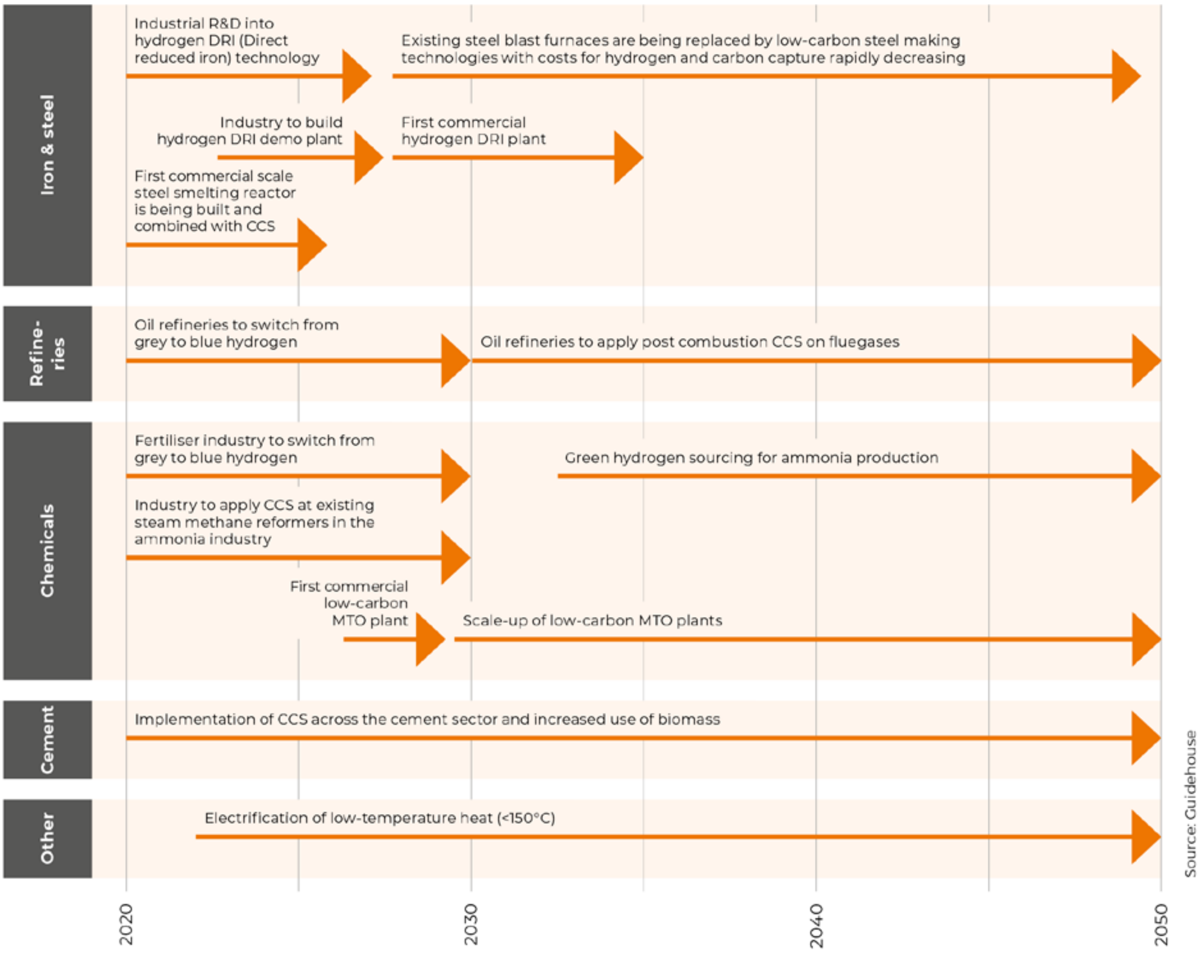
125 A CfD is a contract between an industry company investing in a breakthrough technology and a government body. The idea is that the company is paid by the government body, over a predetermined number of years, the difference between the 'reference price'– the CO_2 price under the EU ETS – and the 'strike price' – a price that reflects the CO2 abatement costs of a particular technology.

In the remaining industry, electrification of low temperature heat is accelerated compared to the Current EU Trends Pathway. High temperature heat pumps provide medium temperature heat (80°C-150°C) in industries such as food and beverages.

Substantial decarbonisation efforts are still needed post 2030. However, in the Accelerated Decarbonisation Pathway, reaching the Gas for Climate 2050 Optimised Gas end state is plausible.

4.3.4 Critical timeline

The following diagram summarises the critical timeline, actions to be taken by industry, and policy recommendations to make the Accelerated Decarbonisation Pathway happen.



4.4 Global Climate Action Pathway – industry

Conclusion Global Climate Action

An ambitious global carbon pricing system would lead to the rapid phaseout of fossil fuels, including natural gas. Biomethane and hydrogen would make up one-third of final energy consumption in industry by 2030.

Already by 2030, all existing steam methane reformers will be retrofitted with CCS. Additionally, large-scale greenfield electrolysers will provide substantial amounts of hydrogen to the industry sectors. In the steel sector, most existing plants will be replaced by direct reduction of iron with hydrogen by 2035. Globally, the fossil fuel industry will gradually switch to producing synthetic fuels from green hydrogen. By 2030, there will be a growing international market for synthetic fuels that are produced and transported at competitive prices as existing transport infrastructure can be repurposed. Due to the emergence of an international market for synthetic fuels, methanol will mostly not be produced from European hydrogen but instead imported at lower costs. Because methanol we be mainly produced outside Europe, EU hydrogen demand is lower in the Global Climate Action Pathway.

4.4.1 Global CO_2 prices

The Global Climate Action Pathway is an evolution of the Accelerated Decarbonisation Pathway. In the early 2020s, countries around the world implement the Paris Agreement by taking ambitious climate action. Converging carbon pricing schemes lead to a global CO_2 price that reaches €55/tCO_2 in 2030. Revenues from this global ETS provide funding for R&D efforts in and implementation at scale of breakthrough technologies.

4.4.2 Technological and cost developments

Global action on decarbonisation will substantially increase R&D efforts on breakthrough technologies. Technological progress and cost reductions will be realised even quicker than in the Accelerated Decarbonisation Pathway. Implementation of pilots will happen inside and outside of Europe, creating best practices and lessons learned which will streamline and accelerate the industrywide deployment of breakthrough technologies

4.4.3 Pathway towards 2050

As fossil fuels become increasingly expensive, a global CO_2 price and the availability of funding will drastically impact the business case for renewable and low carbon gases and for breakthrough technologies. We expect rapid technological advancements related to hydrogen, biomethane, and new industrial technologies. The deployment of breakthrough technologies will increase due to rapid cost reductions of producing renewable and low carbon gas and some technology cost reductions.

By 2030, all existing steam methane reformers will be retrofitted with carbon capture. Additional, large-scale greenfield electrolysers will provide substantial amounts of hydrogen to the industry sectors. In the steel sector, most existing plants will be replaced by direct reduction of iron with hydrogen by 2035. Globally, the fossil fuel industry will gradually switch to producing synthetic fuels from green hydrogen. By 2030, there will be a growing international market for synthetic fuels produced and transported at competitive prices as existing transport infrastructure can be repurposed. Due to the emergence of an international market for synthetic fuels, methanol largely will not be produced from European hydrogen but imported at lower costs. As a result, hydrogen demand in the Global Climate Action Pathway is lower. As a hydrogen infrastructure develops in Europe, we also see that onsite production of hydrogen is gradually being replaced by sourcing of green hydrogen from the hydrogen grid. As a result, electricity demand is decreasing in industry, especially after 2040.

5. Transport Decarbonisation Pathways

Key Takeaways for Road transport

- Under the Current EU Trends Pathway, we expect that ongoing electrification efforts will continue (especially in light vehicles), leading to a steady replacement of existing vehicle types by battery electric vehicles (BEVs). In geographies with less developed electricity and charging infrastructures, light (bio)-compressed natural gas (CNG) vehicles may grow substantially. In heavy road transport, diesel will steadily be replaced by (bio)-LNG up to 2050 as part of the Alternative Fuels Directive. Fuel cell vehicles (FCVs) will not reach full potential due to unfavourable economics and lack of integral policy support for developing a green hydrogen supply chain for road transport.
- Adoption of the European Green Deal in the Accelerated Decarbonisation Pathway will push adoption of BEVs and FCVs between 2020 and 2050 in the light and heavy road transport segments. After 2040, the improving economics of fuel cells and (green and blue) hydrogen will lead to replacing both diesel and gasoline. bio-LNG and bio-CNG are likely to play a role in heavy road transport as well.
- In the Global Climate Action Pathway, global cost reductions in fuel cell and battery technologies results in stronger and early adoption of these technologies.

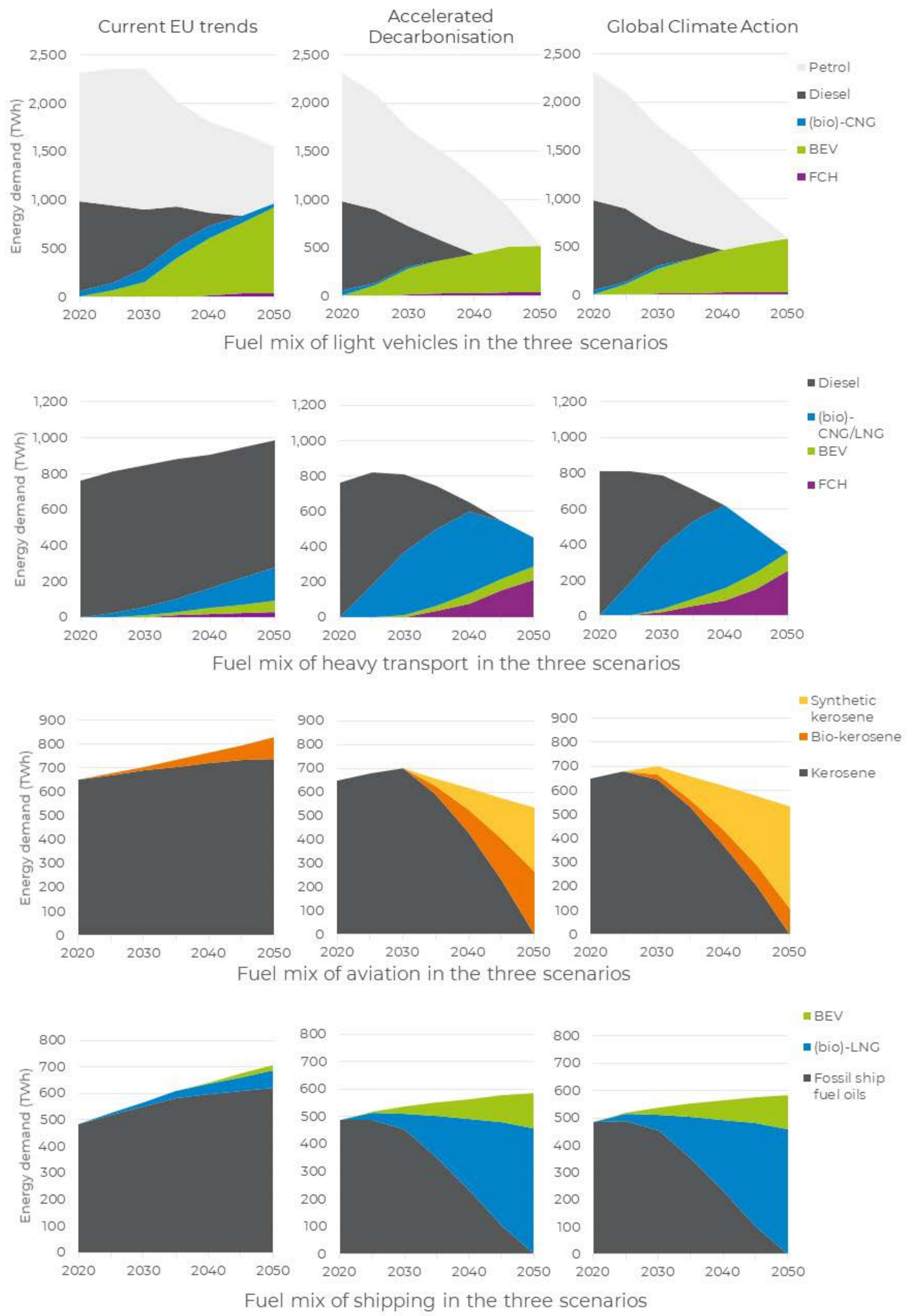
Key Takeaways for shipping and aviation

- Under *Current EU Trends Pathway*, limited developments are foreseen in both sectors by 2030. Reaching net-zero emissions by 2050 will be challenging, also given the expected strong growth in energy demand.
- In the Accelerated Decarbonisaton pathway, ship owners start to purchase new vessels from the 2020s onwards that are compatible to use renewable fuels. It will require strong policy action to stimulate early switching to battery electric vessels, bio-LNG, and other renewable marine fuels.

- In the Accelerated Decarbonisation Pathway, market readiness for biokerosene and synthetic kerosene will be achieved before 2030. This will allow a steady scale-up of renewable aviation fuels towards 2050. To increase the likelihood of reaching full decarbonisation in aviation it is necessary to curb demand growth in air travel.
- The Global Climate Action Pathway results in a larger global availability and reduced cost of renewable aviation and marine fuels. Imports of synthetic kerosene from countries with low renewable power costs and with available refinery capacity can be expected.

This Appendix describes decarbonization pathways for EU transport. The Accelerated Decarbonisation Pathway aims to meet the Gas for Climate Optimised Gas 2050 scenario for net-zero emissions in transport as described in the Gas for Climate 2019 report.[126] The Current EU Trends Pathway is an extrapolation of the impact of current EU policies, while the Global Climate Action Pathway assumes an increased global effort to reduce CO_2 emissions and develop and scale-up clean technologies.

Figure 28. Results of the pathway analyses for three transport scenarios, showing the subsectors light vehicles, heavy transport, aviation and shipping



Source: Guidehouse

126 Navigant, *Gas for Climate*, 2019.

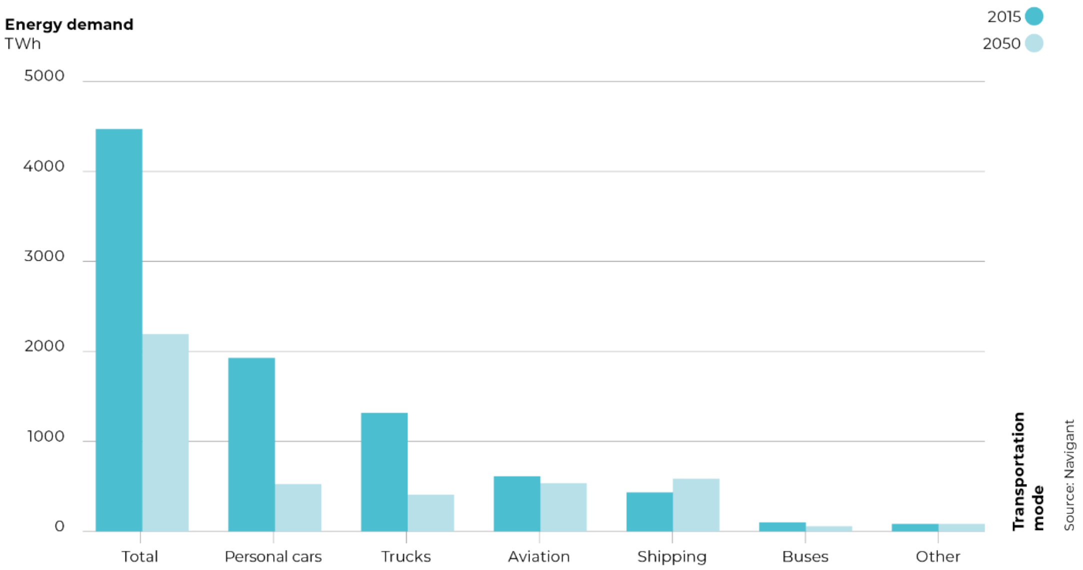
5.1 Introduction

5.1.1 Current situation

In 2017, 27% of total EU greenhouse gas emissions were related to transport. Since 1990, transport emissions increased by 28% (excluding international shipping).[127] Road transport was responsible for nearly 72% of total emissions, followed by aviation (domestic and international) and maritime transport (with around 14% share each), excluding the indirect global warming effects of aviation. Railways only contributed 0.5% to the total sector emissions.

The transport sector's total energy demand was close to 4,500 TWh in 2015 (Figure 29). Most of the energy use in road transport is supplied via diesel (2,280 TWh) and gasoline (900 TWh). Energy use in aviation by kerosene (600 TWh) and in shipping by marine fuels (540 TWh). The role of natural gas consumption in transport was still limited in 2015 at about 20 TWh but has almost doubled from 13 TWh in 2010 and is especially developed in passenger cars.[128]

Figure 29. EU energy use in the transport sector for various subsectors in both 2015 and Gas for Climate 2050 Optimised Gas end state.



5.1.2 Gas for Climate 2050 Optimised Gas end state

By 2050, the EU transport sector must fully decarbonise to meet commitments to reach net-zero CO_2 emissions. The Gas for Climate 2019 study included a transport decarbonisation analysis and concluded that the EU transport sector could reach net-zero CO_2 emissions in 2050. The transport sector can achieve this by adopting transport technologies that can be decarbonised or run on low carbon fuels. In the Gas for Climate 2050 Optimised Gas end state, road transport, shipping, and aviation would develop as described below.

Road transport

Electrification is the key decarbonisation measure in road transport, but for heavy road transport hydrogen and bio-LNG will be important energy carriers as well. The societal costs for various low carbon vehicle fuel options are comparable, which

127 European Environmental Agency, Greenhouse gas emissions from transport in Europe, https://www.eea.europa.eu/data-and-maps/indicators/transport-emissions-of-greenhouse-gases/transport-emissions-of-greenhouse-gases-12, 2020

128 European Environmental Agency, Energy consumption in transport, https://www.eea.europa.eu/data-and-maps/daviz/transport-energy-consumption-eea-5#tab-googlechartid_googlechartid_chart_111, 2020

means that non-cost factors will most likely determine the optimal fuel mix. These factors include the availability of an EU-wide refuelling infrastructure, the impact of the fuel type on available transport payload, and volumes and the existence of specific policies, taxes, and levies that push a specific technology. Based on its analysis, Guidehouse expects the energy demand in road transport to be around 1,000 TWh in 2050. This would be close to half of total energy demand in transport, assuming a large-scale adoption of electric drivetrains in 2050 which reduces the final energy demand by roughly 50% compared to a situation in which only conventional drivetrains are used. In the Gas for Climate 2050 scenario, the deployment of renewable and low carbon gas technologies lead to a hydrogen demand of 252 TWh, a bio-LNG demand of 134 TWh (this could also include bio-CNG), and an electricity demand of 648 TWh.

Shipping

Many future fuel technologies are being considered for the shipping sector. Based on its analysis, Navigant envisions that all existing diesel and marine fuelled vessels will be replaced mainly by bio-LNG and battery electric vessels by 2050, avoiding the need to develop additional production routes for more expensive or scarce biodiesel. However, other fuel options could also become relevant, such as green hydrogen and synthetic ammonia (see also Chapter 5). The deployment of battery and bio-LNG vessels lead to a bio-LNG demand of 461 TWh and an electricity demand of 124 TWh.

Aviation

The aviation sector's energy demand is expected to be around 534 TWh by 2050 as a result of efficiency measures and demand growth reduction. It is estimated that sustainable feedstock for bio jet fuel can make up 50% of the aviation fuel demand, next to 50% synthetic kerosene.

As the Gas for Climate 2019 report began with a net-zero emission sector in mind. This study analyses pathways towards 2050. This section discusses three pathways to reduce CO_2 emissions in the EU transport sector by 2050:

1. The Current EU Trends Pathway considers the current state in the transport sector and the developments, steered by existing market conditions and policies. Current policies will have limited impact after 2030. A tremendous ramp-up of zero-carbon technologies is required after 2030 to reach a 2050 net-zero carbon target.
2. The Accelerated Decarbonisation Pathway considers the European Green Deal's impact if it is adopted and translated into legislation. The pathway assumes that the EU will actively tackle CO_2 emissions, while the rest of the world will be less ambitious in its efforts. From this scenario, we distil recommendations for the Green Deal to be effective in reducing CO_2 emissions in transport and reaching the Gas for Climate Optimised Gas 2050 end state.
3. The Global Climate Action Pathway considers the impact of global climate action with strong cost reductions in zero-carbon technologies and developments in synthetic fuel production.

All scenarios cover the three major transport subsectors: road transport (light vehicles, including passenger vehicles and light commercial vehicles, and heavy road transport, including trucks and long-distance buses or coaches), shipping (domestic, intra-EU, and intercontinental), and aviation. Rail transport is not explicitly covered in our analysis because of its relatively low energy demand compared to the other transport modes. However, the impact of a future modal shift to rail transport predominantly originating in trucks and aviation is assessed. A large part of EU rail transport is already electrified. In the future, diesel powered trains will be electrified and on tracks that are (economically) difficult to electrify, hydrogen or (bio)-LNG could play a role.

Fuel use and its required infrastructure must be similar across Europe to ensure transport will be able to operate internationally. Intercontinental alignment is required for aviation and shipping. Our scenarios consider road transport on internal combustion engines (ICEs) fuelled by diesel, gasoline, CNG and LNG, and BEVs and FCVs. For aviation, we consider kerosene, biokerosene, and synthetic kerosene, and for shipping we consider electricity, diesel/marine fuel oil, and LNG as energy carriers.

The pathways focus solely on energy-related CO_2 emissions, and indirect or non-CO_2 related global warming effects are not accounted for in this analysis. Specifically, air travel has additional effects on global warming through the formation of contrails, ozone, and aerosols. These effects are significant and reported to be potentially twice the effect of CO_2 alone.[129] More precise scientific efforts to quantify these effects are ongoing. Switching to climate-neutral fuels will not address all non-CO_2 warming effects. In addition, the impact of methane leakage in the application of CNG and LNG is not considered quantitatively. Due to the large emission factor of methane compared to CO_2, methane slip in the supply chain can lead to

129 IPCC, Climate Change 2007, https://www.nature.com/articles/s41467-018-04068-0, https://www.ipcc.ch/site/assets/uploads/2018/05/ar4_wg1_full_report-1.pdf.

additional global warming. Over the years, mitigating actions have been undertaken to reduce these methane emissions in gas production, and in its use in transport.

5.2 Transport pathway under current EU climate and energy policies

Conclusion Current EU Trends

Under the Current EU Trends Pathway, we expect ongoing electrification efforts to continue (especially in light vehicles), leading to a steady replacement of existing vehicle types by BEVs. In geographies with less developed electricity and charging infrastructures, light (bio)-CNG vehicles will grow substantially. In heavy road transport, diesel will steadily be replaced by (bio)-LNG up to 2050 as part of the Alternative Fuels Directive. FCV will not reach full potential due to unfavourable economics and lack of integral policy support for developing a green hydrogen supply chain for road transport.

The transformation of the shipping and aviation sectors is slow due to the low rate of unit replacement. Under the Current EU Trends Pathway, limited developments are expected in the sectors before 2030. After 2030, achieving net-zero emissions in 2050 will only be feasible through tremendous upscaling of low carbon fuels, such as bio and synthetic kerosene and marine fuels, especially considering the strong growth of these sectors towards 2050.

5.2.1 EU policies

5.2.1.1 Road transport

The road transport sector is in rapid transition, spurred by strongly decreasing costs[130] for BEVs, increasing emission regulations (at EU, national, and city levels), and increasing costs of ownership for ICEs. EU policies on road transport are mainly built on two pillars:

- The improvement of engine efficiencies through the regulation of CO_2 emissions in vehicles
- The decarbonisation of the fuel mix, mainly through the RED I and II, which resulted in member states forcing a blending percentage of biofuels with conventional fossil fuels

A more detailed list of relevant road transport policies is included in Section A.2.

Biofuels are the largest contributor to decarbonisation in the fuel mix today, despite the public and policy attention for alternative fuel vehicles, BEVs, and FCVs. The use of natural gas in transport is supported as part of the EU's Alternative Fuels Strategy. A more detailed discussion of the role of these fuel types is included in Section A.3.

130 In 2018, battery costs per kWh have dropped by 85% since 2010. By 2030 experts foresee another 65% drop in battery costs compared to 2018, resulting in a cost level of €56/kWh. Source: Bloomberg NEF, Electric Vehicle Outlook 2019, 2019.

5.2.1.2 Shipping

Most of the EU international shipping sector ambitions previously were taken forward through the IMO.[131] IMO's strategy plans to reduce CO_2 emissions by at least 40% in 2030 and pursues efforts to reduce emissions by 70% by 2050.[132] The directive of 2018 reforming EU ETS states that "action from the IMO or the Union should start from 2023, including preparatory work on adoption and implementation and due consideration being given by all stakeholders." Depending on IMO developments, the EU shipping sector could be included in the EU ETS as early as 2023. The European Commission will review the IMO's progress annually to ensure that the sector contributes to the Paris Agreement.[133]

The only EU regulation currently applicable to international shipping requires large ships to report on annual fuel consumption and CO_2 emissions.[134] IMO is expected to develop legally binding measures on operational efficiency in ships and the adoption of low and zero-carbon fuels.[135] Given the long lifetimes of ships, typically 25-30 years, it will be a while before operational efficiency measures in new ships start reducing the overall emissions in the sector. Most new ships are built and sold in East Asia, which could reduce the impact of European-only policies.[136]

5.2.1.3 Aviation

CO_2 emissions from all airlines operating in Europe have been required to surrender CO_2 emission allowances under the EU ETS since 2012.[137] However, in expectance of a global measure by the International Civil Aviation Organisation (ICAO),[138] the scope of the ETS was reduced to the European economic trading zone, which represents about 40% of total EU aviation emissions.[139]. Almost half of the ETS allowances[140] are received by airlines for free, which, together with low ETS price levels, result in a limited impact of the ETS system on ticket prices and demand for aviation.[141]

In 2016, ICAO introduced a global approach to reduce CO_2 emissions from international aviation by 2021. The resolutions aim to "stabilise CO_2 emissions at 2020 levels by requiring airlines to offset the growth of their emissions after 2020."[142] This approach largely builds on a global offsetting scheme called CORSIA. In parallel, the International Air Transport Association set targets for the sector to improve fuel efficiency, have carbon neutral growth after 2020, and reduce CO_2 emissions from aviation by 50% in 2050 relative to 2005 levels. The strategy to reach these targets is based on improved operational efficiencies, deployment of sustainable low carbon fuels, and a global market-based measure.[143] At point of writing, about 30 airline operators offer voluntary carbon offsetting schemes and small-scale blending of kerosene with low carbon options.[144] According to the European Aviation Safety Agency, various initiatives are being deployed in Europe to increase the market penetration for biofuels. However, consumption is low and not expected to increase significantly over the next few years.[145]

131 Transport & Environment, EU shipping's climate record, Maritime CO2 emissions and real-world ship efficiency performance, 2019.

132 International Maritime Organisation, Adoption of the initial IMO strategy on reduction of GHG emissions from ships and existing IMO activity related to reducing GHG emissions in the shipping sector, 2018.

133 European Commission 2018/410, Amending Directive 2003/87/EC to enhance cost-effective emission reductions and low carbon investments, and Decision (EU) 2015/1814, 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L0410&from=EN.

134 European Commission 2015/757, On the monitoring, reporting and verification of carbon dioxide emissions from maritime transport, and amending Directive 2009/16/EC, 2015, http://op.europa.eu/en/publication-detail/-/publication/c895b0b3-fdf7-11e4-a4c8-01aa75ed71a1/language-en.

135 Lloyd's Register, "IMO Strategy – What does it mean?" 2018, https://www.lr.org/en/insights/articles/imo-ghg-strategy-what-does-it-mean/

136 BRS Group, Shipping and Shipbuilding Markets, Annual Review, 2019.

137 2008/101/EC, Amending Directive 2003/87/EC so as to include aviation activities in the scheme for greenhouse gas emission allowance trading within the Community.

138 European Commission, https://ec.europa.eu/clima/policies/transport/aviation_en.

139 Transport & Environment, State of the aviation ETS, 2019, https://www.transportenvironment.org/state-aviation-ets.

140 The number of allowances for aviation (European Aviation allowances, EUAAs) has been capped to 95% of 2004-6 emissions. EUAAS can be traded within the aviation sector. Additional required allowances can be bought on the European Emission Allowances (EUAs) market. In contrast, sectors outside aviation cannot buy EUAAs. As the aviation sector is growing, there has always been a need for the sector to buy EUAs, resulting in similar price levels between EUAAs and EUAs.

141 Transport & Environment, State of the aviation ETS, 2019.

142 International Air Transport Association, Carbon offsetting for international aviation, 2019, https://www.iata.org/policy/environment/Documents/paper-offsetting-for-aviation.pdf.

143 International Air Transport Association, Climate Change, 2019, https://www.iata.org/policy/environment/Pages/climate-change.aspx.

144 International Air Transport Association, IATA Carbon Offset Program, 2019, https://www.iata.org/whatwedo/environment/Pages/carbon-offset.aspx.

145 So far, only Germany reported the use of bio-based aviation fuels in 2016 under the framework of the Emissions Trading Directive, Source: European Aviation Safety Agency, Sustainable Aviation Fuels, 2019, https://www.easa.europa.eu/eaer/climate-change/sustainable-aviation-fuels.

5.2.2 Regional differences today

5.2.2.1 Road transport

Some member states and cities are developing policies that go beyond European legislation. The main driver is the ambition to reduce emissions in cities or to meet local climate targets. CO_2 reduction targets go hand-in-hand with targets to improve city logistics and reduce other emissions, such as particulate matter, NO_x and SO_x. The Netherlands, Norway, France, the UK, Sweden, Ireland, and other member states have already announced plans to phaseout fossil-fuelled cars between 2025 and 2040 and cities (including London, Paris, Amsterdam, and Brussels) want to ban conventional cars in 2030-2035.[146] Some member states oppose stricter emission reduction targets, specifically in Central and Eastern Europe due to the large markets for used cars.[147]

Another example of differences between member state policies is in the support for a switch to alternative fuels in road transport. This difference in support gives rise to remarkable differences in the fleet stock in countries, with Italy having a relatively large fleet of natural gas cars (CNG and LPG), while France, Sweden, Netherlands, and the UK have a larger percentage of BEVs in their alternative fuel markets.[148] Of the CNG/LNG trucks that operate, over 80% are in Italy, Sweden, Spain, and France.[149] The diverging national trends in vehicle fuel use is mainly due to national policies, regional specificities, and share of natural gas in the energy mix.[150] Compared to other continents, the EU market for natural gas vehicles is less developed.

5.2.2.2 Aviation and shipping

Shipping and aviation activities are not equally distributed across the EU, not even across nations with a large shoreline. Based on reported activities, Transport & Environment identifies Western Europe, Italy, and Greece as the main contributors to shipping emissions.[151] The growing LNG demand for shipping can be sourced from already existing LNG import facilities across Europe. Using existing LNG import assets can be a relatively cost-effective way to scale-up demand in the shipping sector as it can improve economics for underutilised LNG assets[152] and it avoids regasification of imported LNG or natural gas liquefaction.

For aviation, large kerosene production facilities exist in Europe, mainly in Spain, Italy, the Netherlands, and the UK. However, due to market conditions and production capacities, around 16 Mt (around 200 TWh) of kerosene was imported from other parts of the world, mainly the Middle East in 2015.[153]

5.2.3 Pathway towards 2050

5.2.3.1 2020–2030

Road transport

Under current policies, the number of vehicles in the EU is expected to continue growing. We adopted a continued 13% growth per decade for light and heavy transport.[154]

BEVs and plug-in hybrid EVs demonstrate a strong increase in the number of registrations and have dominated the market for new registrations in alternative fuel driven cars since 2016.[155] BloombergNEF forecasts around 55% of all passenger vehicle sales in the EU to be battery electric in 2030, which, considering the ramp-up of car sales, could result in a market share of

146 Navigant, Gas for Climate, 2019.
147 Transport & Environment, The end of the fossil fuel car is on the EU agenda, 2019, https://www.transportenvironment.org/news/end-fossil-fuel-car-eu-agenda.
148 European observatory for alternative fuels, 2019, https://www.eafo.eu/alternative-fuels/overview.
149 EA, The future of trucks, 2017.
150 Trinomics, “The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets,” 2019.
151 Transport & Environment, EU shipping’s climate record, Maritime CO2 emissions and real-world ship efficiency performance, 2019.
152 Trinomics, “The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets.”
153 Fuels Europe, *Statistical Report*, 2017.
154 ACEA, “The automobil industry pocket guide,” 2019, https://www.acea.be/uploads/publications/ACEA_Pocket_Guide_2019-2020.pdf.
155 European Alternative Fuel Observatory, 2019, https://www.eafo.eu/vehicles-and-fleet/m1.

15%-20% for BEVs in the EU in 2030. Light and medium commercial vehicles will see adoption of BEVs, especially related to city logistics. Under current policies, limited scale is expected for BEVs in the long-haul, heavy transport segment. Under current policies, CNG use in light vehicles is expected to see a modest continued growth, mainly in countries that have specific policies in place to stimulate adoption, such as in Italy.[156] We estimate that in the EU this could lead to about three times the current amount in light vehicles in 2030. Market share of natural gas (CNG/LNG) in the heavy transport segment shows much stronger growth, which could result in a tenfold growth towards 2030, in line with current growth figures.[157] This would lead to a EU CNG/LNG market share of about 5% for both light vehicle and heavy vehicle segments in 2030.[158]

The number of FCVs in Europe is still limited. However, developments in improved and cheaper fuel cell technologies are speeding up, mainly driven by market developments in Japan and China. In the Hydrogen Roadmap Europe, the first market uptake in Europe is expected between 2025 and 2030. This will occur in niche markets with specific demands on loads and ranges, such as taxis, coaches, and vans. Uptake in passenger cars and trucks is not expected at scale before 2030.[159]

Aviation and shipping

Due to the relatively slow replacement rate of aircrafts and ships in the EU, (lifetime of 20-30 years and a long order time typically up to 5 years), incremental efficiency improvements will only have a small contribution to the overall net-zero emission goal up to 2030. This is especially the case considering the overall demand increase from the aviation sector's growth. Transport & Environment estimates that around 10% of kerosene could be replaced by biokerosene through blending in 2050, which we adopted in our forecast.[160] For 2030, it could be around 2% of kerosene demand.

Following the implementation of the Alternative Fuel Infrastructure Directive, LNG will be available in all EU TEN-T core ports[161] by 2025, which will enable part of the shipping sector to shift to the use of LNG. LNG's market share in the entire fleet will likely be around 3% in 2030, in line with the low scenario developed by TNO and CE Delft.[162]

Both sectors will continue to grow. For shipping, around 50% growth is assumed in 2050 compared to today and for aviation, we assume growth of 23% in energy demand.[163, 164]

5.2.3.2 2030–2050

Under current policies and considering the lifetime of passenger cars is a little over 10 years, BEVs will penetrate the light vehicle market. BloombergNEF predicts sales levels of 65% BEV passenger cars in 2040; however, these sales would not be enough to create a completely decarbonised passenger car sector in 2050.[165] Because of this, gasoline will remain part of the fuel mix in light vehicles in 2050. Diesel will remain the dominant fuel option in heavy and long-distance transport in 2050, with a much smaller market size for (bio)-LNG.

FCVs are not expected to play an important role in road transport after 2030. Under current policies, the Fuel Cell and Hydrogen Joint Undertaking expects that adoption rates will remain less than 1% for passenger cars and 5% for buses and trucks in 2050, largely because of lack of cost reductions in fuel cell technologies.[166]

CO_2 emissions will be reduced through blending in of biokerosene in aviation, up to around 10% in 2050.[167] There will be no role or a very limited role for synthetic kerosene due to high costs and deployment barriers in the EU. In shipping, fleets will continue to shift to using (bio)-LNG when it becomes available in locations at sufficient volumes. However, due to the long

156 European Alternative Fuel Observatory, 2019. https://www.eafo.eu/vehicles-and-fleet/m1.

157 European Alternative Fuel Observatory, 2019. https://www.eafo.eu/vehicles-and-fleet/m1.

158 The Oxford Institute for Energy Studies, *A review of prospects for natural gas as a fuel in road transport*, 2019, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/04/A-review-of-prospects-for-natural-gas-as-a-fuel-in-road-transport-Insight-50.pdf.

159 Fuel Cell and Hydrogen Joint Undertaking, *Hydrogen roadmap Europe*, 2019, https://www.FCEV.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf.

160 Transport & Environment, *Roadmap to decarbonising European aviation*, 2018.

161 The overview of ports in the Trans-European Transportation Network (TEN-T) is available here: http://ec.europa.eu/transport/infrastructure/tentec/tentec-portal/site/en/maps.html.

162 CE Delft, TNO, *Study on the completion of an EU Framework on LNG-fueled ships and its relevant provision infrastructure, Lot 3 Analysis of the LNG market development in the EU*, 2017 https://ec.europa.eu/transport/sites/transport/files/2015-12-lng-lot3.pdf.

163 Transport & Environment, *Roadmap to decarbonising European shipping*, 2018.

164 Transport & Environment, *Roadmap to decarbonising European aviation*.

165 Bloomberg NEF, Electric vehicle outlook 2019, 2019

166 Fuel Cell and Hydrogen Joint Undertaking, *Hydrogen roadmap Europe*, 2019, https://www.FCEV.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf.

167 Transport & Environment, *Roadmap to decarbonising European aviation*, 2018.

lifetimes, in this scenario, a partial switch to (bio)-LNG can be expected at best and fossil ship fuel oils will remain the dominant fuel type.

5.3 Accelerated Decarbonisation Pathway – Transport

Conclusion Accelerated Decarbonisation

Adoption of the European Green Deal in the Accelerated Decarbonisation Pathway will push adoption of BEVs and FCVs between 2020 and 2050 in the light and heavy road transport segments across the EU. After 2040, the improving economics of fuel cells and (green and blue) hydrogen will lead to replacing both diesel and gasoline, and for heavy transport bio-LNG and bio-CNG.

Due to long vessel lifetimes, using natural replacement cycles requires an early market switch to these vessel types, starting in 2025. To meet a net-zero emission goal in 2050 under the Accelerated Decarbonisation Pathway, only new vessels with engines that use or can be retrofitted to use fuels that can be decarbonised should be accepted in shipping, before 2025 or sooner if possible. It will require strong policy action to stimulate early switching to battery electric vessels, bio-LNG and other fuel low carbon fuel types.

Under the Accelerated Decarbonisation Pathway, the market readiness for bio and synthetic kerosene will be achieved before 2030, with a steady scale-up of low carbon fuels production in the EU in aviation towards 2050. This needs to be supported by a reduction in demand for air travel through modal shift.

5.3.1 European Green Deal for transport

5.3.1.1 Legislative plans

Transport will be an important part of the proposed European Green Deal. Several plans for the sector have been presented that will be translated into legislation in upcoming years. These plans include:[168]

- Revise relevant legislative measures, including the EU ETS Directive, Energy Efficiency Directive, RED, Alternative Fuels Infrastructure Directive, and the Trans European Network Transport Regulation, CO_2 emissions performance standards for cars and vans, and the Directive on Combined Transport
- Policy support for deployment of public recharging and refuelling points
- Create more stringent air pollutant emissions standards for combustion engine vehicles
- Apply EU ETS to road transport and the maritime sector and reduce the allocation of free credits to aviation
- Shift a substantial part of the 75% of inland freight carried today by road onto rail and inland waterways and seaways
- Revise the Energy Taxation Directive, which would end current tax exemptions for aviation and maritime fuels

These plans will be strengthened by proposals from individual or groups of member states, such as the call initiated by Denmark for an EU-wide ban on diesel and gasoline cars by 2040, which was backed by 10 member states.[169]

168 European Commission, *The European Green Deal*, 2019, https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

169 Euronews, “Denmark calls for EU ban on all diesel and petrol cars by 2040,” 2019, https://www.euronews.com/2019/10/04/denmark-calls-for-eu-ban-on-all-diesel-and-petrol-cars-by-2040.

5.3.2 Pathway towards 2050

5.3.2.1 2020–2030

Road transport

The increased ambitions in the European Green Deal will further accelerate the uptake of EVs across all segments. The Clean Energy Ministerial campaign (EV 30@30) in 2017 communicated an ambitious goal to speed up the deployment of EVs.[170] In its EV Outlook, the IEA determined this would result in an EU BEV market share of 35% in 2030, which we will adopt for this scenario. The market share of BEV trucks will remain relatively low at around 3%.[171]

As BEV will see a breakthrough in the light vehicle market, the growth in CNG vehicles will focus on countries with established CNG markets and infrastructures[172], possibly based on retrofitting petrol and diesel cars. New car owners will be more likely to choose the more cost-competitive BEV option. Current barriers related to limited charging infrastructure will be taken away by policy support and city bans on ICEs will also impact the adoption of CNG. As a result, automobile manufacturers and fuel station operators will increasingly focus more on BEVs.

In heavy road transport, CNG and LNG have seen a strong growth over the last ten years. This trend can be expected to continue. CNG and LNG vehicle technologies will have an important role in supporting the development of the biomethane market, especially in regions with limited gas pipeline infrastructure. In these regions the uptake of these technologies can be expected to be larger.

The Fuel Cell and Hydrogen Joint Undertaking foresees a potential of around 1.5% FCV passenger cars and less than 1% FCV trucks on the road in 2030.[173] In this scenario, the remainder of the road transport market will be based on ICEs (65% of the total market in 2030).

At current price levels or at expected 2030 levels of around €55/tCO_2, including the transport sector in ETS will have an impact on fuel costs and demand. However, implementation of fuel performance standards will have a larger potential impact. A significantly larger CO_2 price (exceeding €200/tCO_2) would be required to have an impact on the transport sector comparable to fuel performance standards.[174] Future vehicle stock for road transport is based on the IEA Mobility Model. From the model, we take the forecast number of vehicles in Europe up to 2050 within the below 2°C scenario for the EU 27.[175]

Aviation and shipping

Due to the generally slow replacement rate of aircrafts and ships in the EU, (lifetime of 20-30 years and a long order time of typically up to 5 years), incremental efficiency improvements will only have a small contribution to the overall net-zero emissions goal up to 2030. This is particularly the case considering the overall demand increase from aviation sector growth up to 2030.

For aviation to have a sufficiently large supply of fossil-free kerosene to decarbonise the sector, pilot programmes need to be developed before 2030 to enable fast scale-up after 2030. Fuel blending targets can be effective to stimulate the market for non-fossil kerosene. Airports like Schiphol and Heathrow have already called for obligatory blending to stimulate market development.[176]

170 IEA, *New CEM campaign aims for goal of 30% new electric vehicle sales by 2030*, 2017, https://www.iea.org/news/new-cem-campaign-aims-for-goal-of-30-new-electric-vehicle-sales-by-2030.

171 IEA, *Global EV Outlook 2018*, https://www.iea.org/reports/global-ev-outlook-2018.

172 EU Directive 2014/94/EU on alternative fuels infrastructure requires member states to draw up plans for scaling-up alternative fuels infrastructure, see: https://ec.europa.eu/transport/themes/urban/cpt_en

173 Fuel Cells and Hydrogen Joint Undertaking, *Hydrogen Roadmap Europe*, 2019, https://www.FCEV.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf.

174 Cambridge Economics, *The Impact of Including the Road Transport Sector in the EU ETS*, 2014, https://www.ebb-eu.org/EBBpressreleases/Cambridge_ETS_transport_Study.pdf.

175 IEA, *Mobility Model,* https://www.iea.org/etp/etpmodel/transport/.

176 Noordhollands dagblad, Schiphol bepleit verplicht bijmengen biokerosine, 2019, https://www.noordhollandsdagblad.nl/cnt/dmf20191206_34338840/schiphol-bepleit-verplicht-bijmengen-biokerosine?utm_source=www.rtlz.nl&utm_medium=referral&utm_content=/beurs/bedrijven/artikel/4947536/schiphol-baas-benschop-klimaatneutraal-vliegen-biobrandstof

Following the implementation of the Alternative Fuel Infrastructure Directive, LNG will be available in all EU TEN-T core ports by 2025,[177] which will enable part of the shipping sector to shift to LNG.[178] Greenhouse gas reduction will only become substantial when bio-LNG is used, which is expected to reach scale after 2030.[179] For domestic and parts of intra-EU shipping, we assumed a switch to battery electric ships in the Gas for Climate 2050 vision;[180] however, it will require large battery cost reductions and development of fast charging or battery replacement infrastructure to make this an economically feasible option. In this segment, hydrogen powered ships could play an important role.[181] To meet the 2050 Gas for Climate vision, early adoption or retrofitting solutions of low carbon technologies must be promoted early to be able to use the natural replacement cycles.

5.3.2.2 2030–2050

Road transport

The market share of BEVs continues to increase, with sales figures reaching over 65% in the EU between 2030 and 2040.[182] Following current proposals by member states, we assume that after 2040 the EU will completely ban the sales of fossil fuels and that BEV sales percentage increases to 100% for passenger and light commercial vehicles. This will result in an almost fully electrified light vehicle market in 2050.

The market for heavy trucks will become largely electrified, especially in the segment related to short distance logistics. As prices drop for fuel cells and hydrogen, trucks will also switch from diesel to hydrogen. A share of bio-LNG and possibly bio-CNG trucks will remain between 2040 and 2050. Market penetration for fuel cell electric trucks will increase from 3% in 2030 to 50% in 2050. This is in line with the potential of 1.7 million hydrogen trucks in 2050 by the Fuel Cell and Hydrogen Joint Undertaking,[183] considering a decrease of the number of trucks due to modal shift to below 4 million in 2050.[184]

Aviation and shipping

After 2030, scale-up developments are required in in the aviation sector to achieve the levels of bio and synthetic kerosene needed to avoid fossil fuel emissions. Compared to the Current EU Trends Pathway, demand for aviation is reduced from around 830 TWh to 530 TWh through increased ticket pricing, taxation, or further inclusion in ETS, and a modal shift to rail in line with an analysis from Transport & Environment.[185] We assume that all fuel required for the sector is produced in the EU. It will require fast scale-up of bio-based or synthetic kerosene production facilities to meet the estimated 530 TWh of kerosene demand in the EU in 2050, which would still be about 20% higher than EU production of conventional kerosene in 2017.[186] Synthetic kerosene would be half of the 2050 demand, for which large amounts of hydrogen are required.

In shipping, developments that began before 2030 will continue, steadily replacing the fleet by electric ships and by ships that run on (bio)-LNG. The development of the shipping sector depends on technology and fuel cost developments and their availability. Operating cost factors directly influence investment decisions. While this is true for all sectors, for the shipping sector such investment decisions are likely to be relevant for vessels that are still part of the fleet by 2050. Long vessel lifetimes mean that rapid developments in operating costs could result in increased write-off and replacements. We assume that eventually all existing diesel and marine fuelled vessels will be replaced by battery electric and bio-LNG vessels in 2050,

177 The overview of ports in the Trans-European Transportation Network (TEN-T) is available here: http://ec.europa.eu/transport/infrastructure/tentec/tentec-portal/site/en/maps.html

178 CE Delft, TNO (2017). Study on the completion of an EU Framework on LNG-fueled ships and its relevant provision infrastructure, Lot 3 Analysis of the LNG market development in the EU.

179 In addition to fuel switching options in the shipping sector, there are some quick CO_2 reduction opportunities in the shipping sector. A combination of moderate (10%-15%) speed reduction and switch to zero carbon fuels/energy for auxiliary engines/boilers could already result in a 40% CO_2 emission reduction by 2030.This impact has not been taken into account in our pathway analysis. Source: Transport & Environment, *European shipping's climate record*, 2019, https://www.transportenvironment.org/publications/european-shippings-climate-record.

180 Navigant, *Gas for Climate*, 2019.

181 Marigreen, "Perspectives for the Use of Hydrogen as Fuel in Inland Shipping," 2018, http://marigreen.eu/wordpress_marigreen/wp-content/uploads/2018/11/Hydrogen-Feasibility-Study-MariGreen.pdf.

182 BloombergNEF, *Electric vehicle outlook 2019*, 2019.

183 Fuel Cells and Hydrogen Joint Undertaking, *Hydrogen Roadmap Europe*, 2019, https://www.FCEV.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf.

184 Navigant, *Gas for Climate*, 2019.

185 Transport & Environment, *Roadmap to decarbonising European aviation*, 2018, https://www.transportenvironment.org/sites/te/files/publications/2018_10_Aviation_decarbonisation_paper_final.pdf.

186 Fuels Europe, *Statistical report 2019*, https://www.fuelseurope.eu/wp-content/uploads/FuelsEurope-Statistical-Report-2019-2.pdf.

avoiding the need to develop additional production routes for more expensive and scarce biodiesel.[187] However multiple fuel options are still being considered for the sector after 2030 (see section 5.5.4)

5.3.3 Critical timeline

Transport will be an important part of the proposed EU Green Deal. Several plans for the sector have been presented that will become legislation in upcoming years.[188] The Accelerated Decarbonisation Pathway envisions strengthened decarbonisation efforts in the following sectors:

- Road transport: The road transport sector is in rapid transition. This transition is spurred by decreasing costs[189] for battery EVs (BEVs), increasing emissions regulations (at EU, national, and city levels), and increasing costs of ownership for ICEs. The EU Green Deal's plans will have a strong impact on the amount of road transportation: road freight will switch to rail and shipping. The Accelerated Decarbonisation Pathway envisions a push in adoption of BEV and FCV between 2020-2050 in the light and heavy road transport segments across the EU. Due to the improving economics of fuel cells and green and blue hydrogen, after 2040, these technologies will replace both diesel and gasoline. In heavy transport hydrogen will become the dominant fuel while a share of bio-LNG and possibly bio-CNG will remain

- Shipping: Currently, ships have long natural replacement cycles, of 20-30 years. These long cycles, limit fast adoption of new fuel technologies and an early switch would be required to meet the 2050 goal, considering that in 2050 around 30% of the fleet will have been built between 2020 and 2030. At the same time, new ship investments typically only are a small part of the total costs of ownership. A switch to lower fuel cost options will therefore be likely if these become available, even if that would mean a faster write-off. Nevertheless, when comparing against current fossil fuels, it will require strong policy action to stimulate switching to zero emission ships (battery electric and fuel cell electric) and ships that run on (bio-)LNG.

- Aviation: Market readiness for non-fossil kerosene should be achieved before 2030, allowing for a rapid scale-up of non-fossil kerosene production after 2030 paired with an overall reduction of demand for aviation. In the Accelerated Decarbonisation Pathway, the large-scale deployment of bio and synthetic kerosene is expected to start around 2030. Due to increasing fuel costs and efficiency improvements, overall aviation fuel demand could decrease to around 535 TWh by 2050.[190] This demand will be met by 267 TWh of bio jet fuel and 267 TWh of synthetic jet fuels based on hydrogen from electrolysis.

To reach a net-zero carbon transport sector by 2050, the following actions must be developed in addition or in line with the proposed European Green Deal legislation:

- EU-wide development of charging and fuelling infrastructure for LNG, FCV, and BEV fast charging in road transport and shipping (both waterways and seaports).
- Global collaboration on synthetic fuel development for aviation and programming EU pilots to speed up market readiness of synthetic kerosene production.
- Increased emission regulation for road transport, including a ban on fossil fuel ICEs for light vehicles after 2040.
- Progressive regulation on blending biofuels or synthetic fuels with conventional fuels for the full transport sector including road transport, shipping, and aviation, to stimulate market demand for low carbon fuels.
- Standards for the delivery and use of CNG and LNG in vehicle engines and ships focused on reducing methane slip.
- Obligatory fuel use or engine retrofitting standards for specific types of new ships that operate in the EU to ensure the sector can transition to net-zero emissions in 2050 using natural replacement cycles with limited stranded assets.

EU-wide development of charging and fuelling infrastructure

The shift from gasoline and diesel fuels to alternative energy carriers requires an EU-wide development of (fast) charging and fuel infrastructure for (bio-)LNG and hydrogen for light vehicles and trucks. In ports, LNG infrastructure should be available

187 Navigant, *Gas for Climate*, 2019.

188 European Commission, *The European Green Deal*, 2019, https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.

189 In 2018, battery costs per kWh have dropped by 85% since 2010. By 2030 experts foresee another 65% drop in battery costs compared to 2018, resulting in a cost level of €56/kWh. Source: Bloomberg NEF, Electric Vehicle Outlook 2019, 2019.

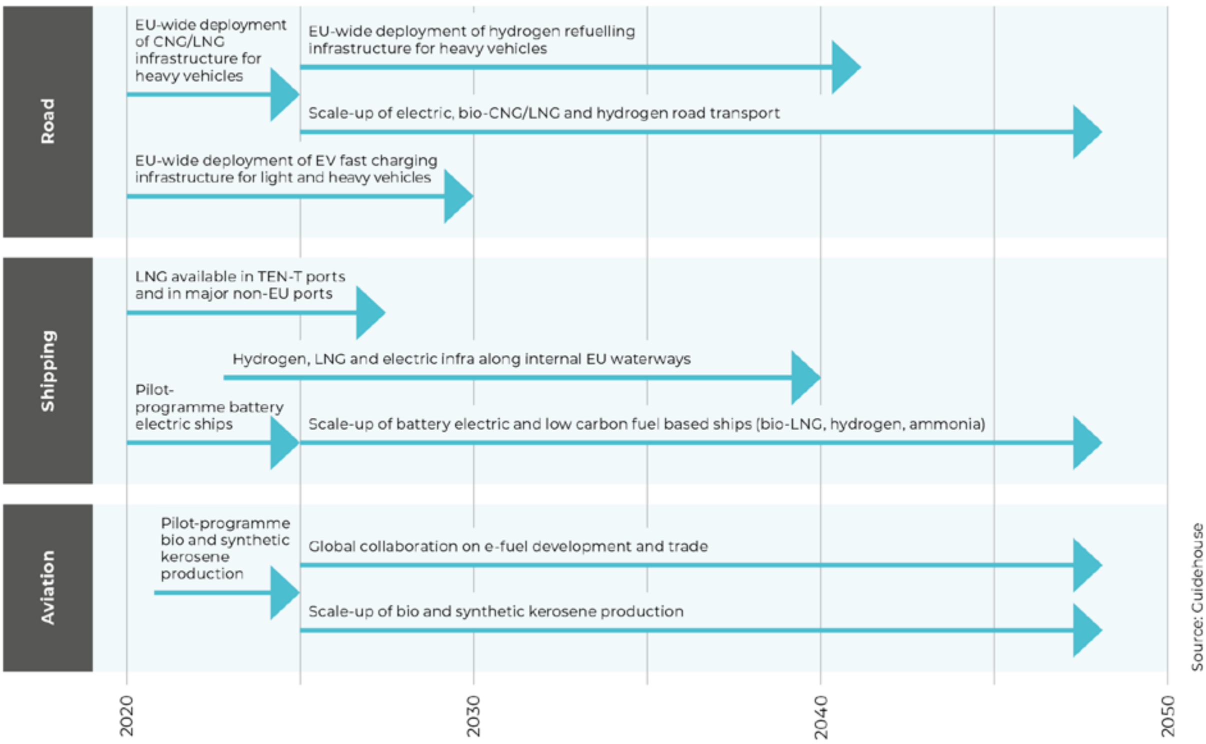
190 Transport & Environment, Roadmap to decarbonising European aviation, 2018

along ports of the Trans-European Transport Network (TEN-T) and in major non-EU ports. Along internal EU waterways, hydrogen, LNG, and electricity infrastructure is required.

Collaboration on synthetic fuel development for aviation

To produce the synthetic kerosene fuelled in the EU by 2050, around 380 TWh of hydrogen is needed. EU refineries will also require significant adjustments to process these amounts of bio and synthetic kerosene. As a result of decreasing demand for gasoline and diesel, it is estimated that refining capacity will become available to process kerosene domestically, allowing a steady scale-up of bio- and synthetic kerosene production in the EU towards 2050. This must be supported by a reduction in demand for air travel through a modal shift. Global collaboration on synthetic fuel development for aviation and programming EU pilots is required to speed up the market readiness of synthetic kerosene production.

Figure 30. Critical timeline transport



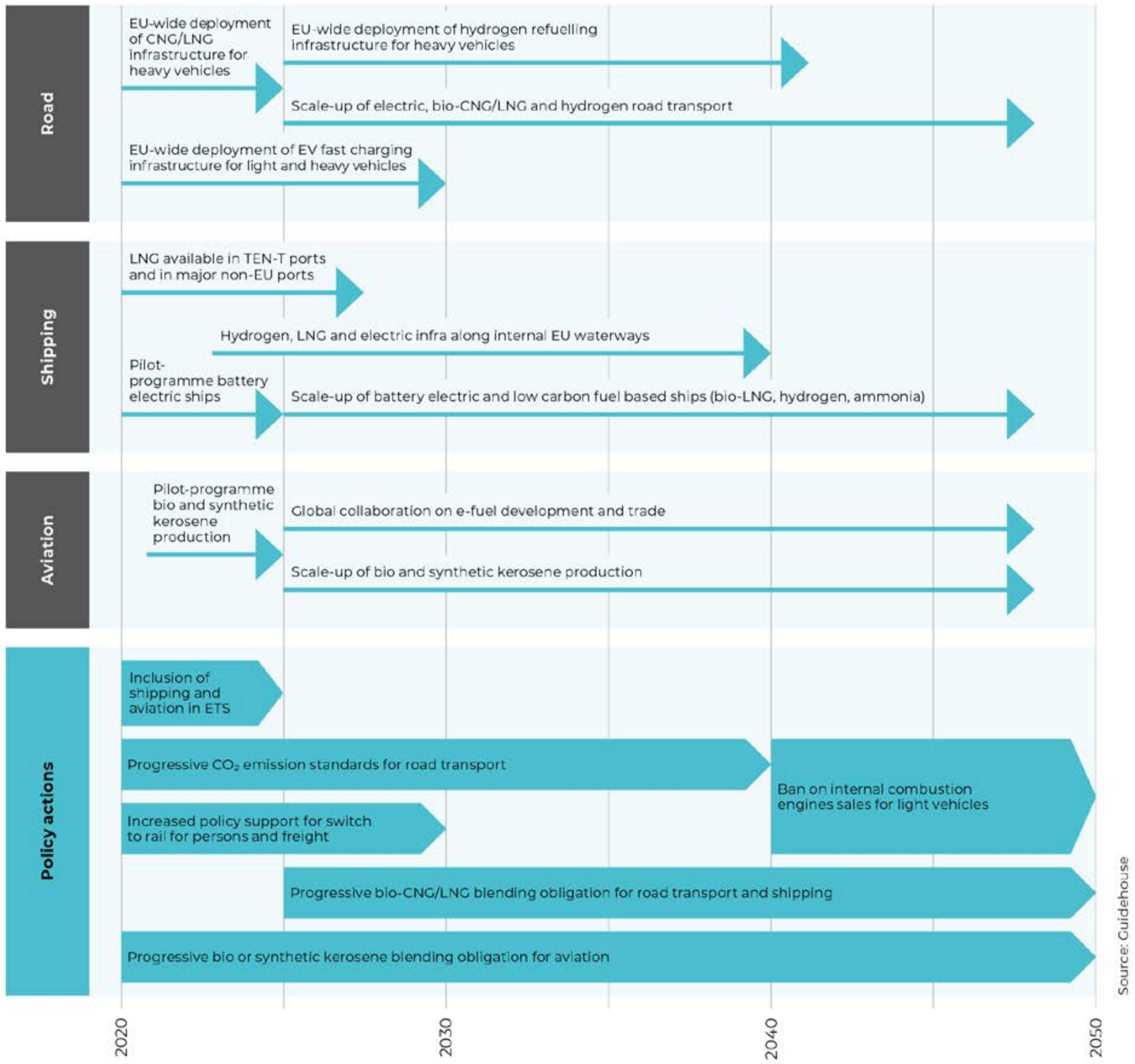
Automated driving with shared car ownership and mobility as a service (MaaS) will improve economics of EVs and FCVs due to their low operating costs compared to internal combustion engines (ICEs). R&D and support for these breakthrough developments are part of the larger climate agenda.

5.3.4 Policy recommendations

Under the Current EU Trends Pathway, under the Current EU Trends Pathway, we expect ongoing electrification efforts will continue, especially in light vehicles. However, current policies do not deliver enough momentum to decarbonise heavy road transport, shipping, and aviation in line with the Accelerated Decarbonisation Pathway described in section 5.3.

There is a diverse set of policies impacting the transport sector. In general, EU's road transport policies are mainly built on two pillars: improvement of engine efficiencies (regulation of CO_2 emissions in vehicles) and decarbonisation of the fuel mix (RED I and II).

Figure 31. Critical timeline and policy actions for transport



The main barrier to an accelerated decarbonisation of long-distance heavy road transport, shipping, and aviation, is the lack of drivers for transport companies to start sourcing more expensive renewable transport fuels and to invest in low-carbon equipment. The fact that aviation and marine fuels have low levels of taxation raises these barriers. This in turn prevents fuel suppliers from ramping up their production, and their innovation efforts, which should together drive down the costs. Additionally, the corresponding renewable fuel infrastructure needs to be made ready.

To move towards the Accelerated Decarbonisation Pathway, we recommend the following policies:

1. International coordination of fuelling infrastructures for CNG, LNG, hydrogen, and electric charging to remove some of the barriers to adoption in long-distance and heavy transport. Introduction of standards for CNG fuelling stations that allow cost-effective conversion to hydrogen.

2. Increase the ambition level of the Alternative Fuels Infrastructure Directive to ensure that the right fuelling and charging infrastructure is in place across Europe and beyond the current TEN-T geographical coverage.

3. Introduce a progressively increasing blending mandate for shipping and aviation fuels in the RED, starting at 14% by 2030 and gradually increasing to 100% by 2050. This policy measure can be an effective alternative to the inclusion of aviation and shipping in the EU ETS.

Only an additional €60 is required to fly carbon neutral from Frankfurt to Rome

The distance from Frankfurt to Rome is about 1,000 km. For most Europeans, this is too far to travel by train. Since the aviation market is dealing with intense competition, the price for a ticket is important. The current ticket price is €230. With an ETS price for aviation of €150/tCO_2 this ticket price will become around €275. Our analysis shows that switching to 100% bio jet will lead to an increased ticket price of €290 based on 2030 price levels. If we move towards 2050 to a 50% bio jet and 50% e-fuel situation, the ticket price will increase to €300. In other words, for about €60 euros extra compared to current price, the flight from Frankfurt to Rome can be carbon neutral in 2030. At current bio jet price levels, this would an additional cost of around €100.

5.4 Global Climate Action Pathway

Conclusion Global Climate Action

In the Global Climate Action Pathway, global cost reductions in fuel cell and battery technologies will result in stronger and early adoption of these technologies in road transport. Market uptake is supported by breakthrough innovations in automated transport and MaaS. The use of fuel cells and batteries in heavy road transport will scale-up before 2030, resulting in these technologies dominating the market in 2050.

Global Climate Action Pathway results in a larger global availability of low cost synthetic fuels. For EU aviation, large-scale imports of synthetic kerosene produced in areas with low renewable power costs and availability of refinery capacity will result in an even stronger role for this fuel type in aviation.

5.4.1 Global Action Pathway towards 2050

Road transport

In the Global Climate Action Pathway, battery and fuel cell technologies are expected to develop faster. The rapid development of these technologies enables faster adoption in road transport. Breakthrough developments in this sector include automated transport and carsharing/MaaS. The combination of the two results in a much-reduced number of vehicles and a higher utilisation per vehicle. This favours the use of vehicles with high efficiencies and low operational costs (mainly BEVs and FCVs), and results in a faster adoption of BEVs in the light vehicles segment. The business case for electric transport is improved if vehicle-to-grid services are developed and implemented for the future, in which case the vehicle battery can act as storage to support matching demand response in the power market. The ICE is phased out quickly because of relatively high operational costs for fuel.

Developments in battery and fuel cell technologies stimulate faster adoption in trucks. Issues of limited driving range for battery electric trucks and buses could be reduced through the development of catenary lines along major European highways, resulting in improved vehicles efficiencies and the adoption of hybrid electric FCVs. Due to the fast development of BEVs and FCVs in the sector, there will not be a large role for (bio)-LNG as an intermediate fuel type towards 2050.

Aviation and shipping

Although breakthroughs in engine efficiency and new fuel technologies are important for both sectors, the long replacement period of vessels and planes will limit the penetration of these technologies in 2050. To reach a net-zero emission aviation and shipping sector in 2050, developments that support decarbonisation of fuels should be prioritised.

For shipping, natural replacement cycles should be maximised to adopt fuel types that can be decarbonised economically, such as electricity, hydrogen, ammonia and LNG. The pathway is assumed to be similar the Accelerated Decarbonisation Pathway.

For aviation, global action will result in greater availability of synthetic fuels produced from green hydrogen and captured CO_2 around the world. EU imports of synthetic kerosene will likely be more economic than importing hydrogen to make synthetic kerosene in the EU. This is especially the case given the relatively large energy costs for producing and shipping liquified hydrogen and the fact that global infrastructure is already in place for kerosene trade with the EU already importing 30%-35% of its kerosene demand.[191] Imports can be expected from areas of the world that have low cost renewable power, electrolysis capacity, and the availability of CCU/CCS and refinery infrastructures. This pathway assumes synthetic kerosene has similar or lower costs than biokerosene. We assume a share of 80% synthetic kerosene and 20% biokerosene in the 2050 aviation fuel mix.

5.5 Additional background on transport

5.5.1 Gas for Climate vision on transport in 2050

Navigant analysed the potential role of renewable and low carbon gas in the transport sector as part of the Gas for Climate 2019 report. This Appendix is based on section 4.4.5 of that report and outlines conclusions on the most cost-effective solutions for transport in 2050.[192]

Table 6. Technology deployment in the transport sector (%)

Sector	Technology	Optimised gas
Passenger cars	BEV	95%
	FCV	5%
Light commercial vehicles	BEV	90%
	FCV	10%
Freight trucks	BEV	30%
	FCV	50%
	Bio-LNG or possibly bio-CNG	20%
	Advanced biodiesel	0%
Buses	BEV	75%
	FCV	25%
	Advanced biodiesel	0%
Aviation	Synthetic kerosene	50%
	Biojet fuel	50%
Shipping | Domestic	Electricity	100%
Shipping | Intra-EU	Electricity	50%
	Bio-LNG	50%
	Advanced biodiesel	0%
Shipping | Outbound EU	Bio-LNG	100%
	Advanced biodiesel	0%

Source: Guidehouse

191 Fuels Europe, Statistical report 2019, https://www.fuelseurope.eu/wp-content/uploads/FuelsEurope-Statistical-Report-2019-2.pdf.
192 Navigant, *Gas for Climate*, 2019.

Table 7. Energy demand in the transport sector (TWh)

Energy carrier	Optimised gas
Bio-LNG	595
Hydrogen	252
Electricity	772
Biofuel	267
Synthetic kerosene	267
Total	**2,172**

Source: Guidehouse

5.5.2 Current EU transport policies

The European Commission developed a strategy that should bring the transport sector towards the target of a 60% reduction of CO_2 emissions by 2050, as described in the *Roadmap to a Single European Transport Area*.[193] The roadmap identifies goals for guiding policy action on various topics:

Fuel switch goals

- Reduce the use of petrol and diesel cars in cities by half by 2030, phasing them out completely by 2050 and achieve CO_2-free city mobility by 2030.
- Increase the use of low carbon sustainable fuels in air transport to 40% by 2050.
- Reduce EU CO_2 emissions from ship fuels by 40% by 2050.

Modal shift goals

- Switch 30% of road freight travelling over 300 km to rail and waterborne transport by 2030, and over 50% by 2050.
- Triple the existing highspeed rail network by 2030. Most of the medium-distance passenger transport should go by rail by 2050.

Transport infrastructure integration goals

- Establish a fully functioning, EU-wide TEN-T core network integrating all forms of transport by 2030.
- Connect major airports to rail and core seaports and rail and inland waterways by 2050.

To achieve these goals, policies have been established that focus on specific parts of the transport sector:

- **Directive for clean and energy efficient road transport vehicles:**[194] Promotes and stimulates the development of a market for clean and energy efficient vehicles.
- **General and CO_2 emission performance standards for heavy duty vehicles:**[195, 196] After performance standards for NO_X and particulate matter emissions, the first CO_2 emission performance regulation for heavy trucks was adopted in 2019, setting targets for reducing the average emissions for new trucks for 2025 and 2030. The regulation also includes a mechanism to stimulate the uptake of zero and low emission vehicles.[197]
- **CO_2 emission performance standards for light commercial vehicles**[198] **and passenger cars:**[199] These vehicles have been regulated from 2011 and 2009, respectively. However, the regulations do not set more stringent targets for light commercial vehicles beyond 2020 or for passenger cars beyond 2021.
- **Combined Transport Directive:**[200] Promote a shift from road freight to other transportation modes (inland waterways, maritime transport, and rail). Over the last 25 years, the directive has helped shift a considerable amount of freight away from road. However, the European Commission is considering strengthening the directive to keep its impact high.[201]

193 European Commission, *Roadmap to a single European transport area: Towards a competitive and resource-efficient transport system*, 2011, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52011DC0144&from=EN.

194 EC 2019/1161, "On the promotion of clean and energy-efficient road transport vehicles," 2019, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L:2019:188:FULL&from=EN.

195 EC 582/2011, Implementing and amending Regulation (EC) No 595/2009 of the European Parliament and of the Council with respect to emissions from heavy duty vehicles (Euro VI) and amending Annexes I and III to Directive 2007/46/EC of the European Parliament and of the Council, 2011, https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:167:0001:0168:EN:PDF.

196 EC 2019/1242, Setting CO_2 emission performance standards for new heavy duty vehicles and amending Regulations (EC) No 595/2009 and (EU) 2018/956 of the European Parliament and of the Council and Council Directive 96/53/EC, 2019, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R1242&from=EN.

197 European Commission, *Reducing CO2 emissions from heavy-duty vehicles*, 2019, https://ec.europa.eu/clima/policies/transport/vehicles/heavy_en.

198 EC 510/2011, *Setting emission performance standards for new light commercial vehicles as part of the Union's integrated approach to reduce CO_2 emissions from light-duty vehicles*, 2011, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32011R0510&from=EN.

199 EC 443/2009, *Setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO_2 emissions from light-duty vehicles*, 2009, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009R0443&from=EN.

200 92/106/EEC, "On the establishment of common rules for certain types of combined transport of goods between Member States," 1992, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:31992L0106&from=EN.

201 European Parliament, *JD – Proposal for a directive on common rules for combined transport of goods*, 2019 https://www.europarl.europa.eu/legislative-train/theme-resilient-energy-union-with-a-climate-change-policy/file-jd-combined-transport-directive-review.

- **RED:**[202] Enforces that at least 10% of transportation fuels in the EU come from renewable sources by 2020 and at least a 14% share of renewable energy in transport in 2030. RED drives current blending of biofuels with petrol and diesel.
- **Alternative Fuels Infrastructure Directive (AFID):**[203] Requires that EU members develop national policies to facilitate adoption of alternative fuels: e.g., CNG, LNG, electricity, and hydrogen for road transport. LNG and CNG adoption should be coordinated with the implementation of the Ten-T Core Network, which aims to have an appropriate number of refuelling points available in 2025. Electric charging infrastructure should be publicly accessible in suburban and urban conglomerates and in other densely populated areas.
- **Road and fuel taxes:** Such taxes are in place in many countries, which impacts the driving behaviour and economics of road transport. For trucks, changes in fuel taxes have directly affected the decisions made in the logistics system, for instance, increasing loads and reducing distances driven.[204]

5.5.3 LNG and CNG use in transport

Due to increasing tailpipe emission standards (NO_X, particulate matter), CNG and LNG are a replacement option of diesel engines, in duel fuel or dedicated CNG or LNG trucks, and as LNG in the shipping sector. According to IEA, compared with China and the US, EU countries currently lack a clear competitive fuel price advantage, a comprehensive fuelling station network, and (until recently) government incentives. This is a reason for the EU's relatively low market size for CNG/LNG trucks. Of trucks that operate, over 80% are in Italy, Sweden, Spain, and France.[205] For cars, the main CNG sales are in Italy.[206]

The use of CNG in road transport directly competes with the use of electricity and hydrogen in BEVs and FCVs in the 2050 end state.[207] Comparing total cost of ownership for these fuel types, BEVs and FCVs are more cost-competitive towards 2050. The role of CNG is mainly as an intermediate fuel, with a potential role as an accelerator of a biomethane market when used as bio-CNG. Part of the CNG fuel station infrastructure can be converted to hydrogen to accelerate the deployment of FCVs. Fuel station technical standards should be developed that facilitate this conversion.

In our Current EU Trends and Accelerated Decarbonisation Pathways, CNG/LNG will have a role for long haul heavy trucks in 2050. LNG is also considered as a potential alternative to the conventionally used heavy fuel oil and marine diesel oil, mostly because of its potential to reduce SO_X and NO_X emissions. A large push for LNG as a marine fuel came from the EU Alternative fuels directive,[208] obligating member states to make bunkering infrastructure available in their territories and allowing funding through the Connecting Europe Facility.[209]

Well-to-wheel CO_2 emissions for CNG vehicles are typically slightly lower than petrol. For heavy diesel trucks, there could be a small advantage in using LNG. However, emissions remain relatively large due to the fundamental inefficiencies of ICEs and use of fossil fuel, unless bio-CNG and bio-LNG are used.[210] In terms of greenhouse gas emissions, ICCT concludes that for some production routes, well-to-wheel CNG and LNG use in trucks and shipping can cause more greenhouse gas emissions than conventional fuels.[211] Along the (bio-)methane supply chain, various actions are undertaken to avoid greenhouse gas emissions due to methane leakage and slip.[212] With a reduction of methane slip during the production and use of bio-CNG/LNG, net-zero greenhouse gas emissions can be achieved.

5.5.4 Fuel options in shipping

Multiple fuel options are still being considered in the shipping sector

In 2019, the Gas for Climate analysis provided a low carbon 2050 end state for the shipping sector, ultimately selecting three fuel/engine types: biodiesel/ICE, bio-LNG/ICE and BEV. There are however many more options available in literature such as methanol, ammonia (NH_3) or hydrogen in either ICE or fuel cell type engines. The sector sees pilots and technological

202 EU 2018/2001, "On the promotion of the use of energy from renewable sources,' 2018, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN.

203 2014/94/EU, "On the deployment of alternative fuels infrastructure," 2014, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32014L0094&from=en.

204 IEA, The future of trucks, 2017.

205 IEA, *The future of trucks*, 2017.

206 European observatory for alternative fuels, 2019, https://www.eafo.eu/alternative-fuels/overview.

207 Navigant, *Gas for Climate*, 2019

208 IEA, *The future of hydrogen*, 2019.

209 UMAS, *LNG as a marine fuel in the EU*, 2018.

210 The Oxford institute for energy studies, *A review of prospects for natural gas as a fuel in road transport*, 2019.

211 ICCT, *Assessment of the fuel cycle impact of liquefied natural gas as used in international shipping*, 2013.

212 TNO, *Environmental and Economic aspects of using LNG as a ship fuel in the Netherlands*, 2011.

advancements across these options, illustrating the need to explore such developments further. To test the robustness of this end state as well as to explore pathways of reaching this end state, we performed a sensitivity analysis on the Gas for Climate 2019 assessment by:

- A top-level operating cost reassessment of fuel/engine combinations in the projected 2050 end state, including ship CAPEX and infrastructure costs for LNG
- Qualitatively exploring the impact of accelerated retirement or retrofitting of ships in order to meet this 2050 end-state

Insights

CAPEX required for ship propulsion systems and auxiliary equipment can make up only a small fraction of total operating costs when discounted over a 30-year technical lifetime. Except for batteries and fuel cells in some cases, operating costs are dominated by fuel costs.

Low carbon fuel costs are highly influenced by conversion efficiencies. Fuel/engine combinations show variation in their specific fuel consumption, that is, the amount of fuel consumed for each unit of power output. Low carbon fuels have embedded efficiency losses on top of this. For example, it takes an estimated 2.29 MJ of electricity to produce 1 MJ of ammonia today, this is projected to improve to 1.85 MJ electricity per MJ ammonia by 2050.[213] By connecting energy input costs as used in this study to energy output, we see the following cost estimates expressed as cost per unit energy output. Green methanol combustion and e-diesel combustion were not further explored as their energy conversions were too low to be realistically competitive to the other options.

Table 8. Fuel conversion efficiencies and energy output costs of fuel/engine combinations.

Fuel/Engine types:	Biodiesel/ICE	BEV	H_2/FC	H_2/ICE	NH_3/FC	NH_3/ICE	Bio-LNG/ ICE
Primary energy input	biodiesel	electricity	hydrogen	hydrogen	hydrogen	hydrogen	biomethane
Energy output/input	0.42	0.81	0.41	0.32	0.41	0.32	0.42
Fuel costs 2050 (€ / MWh output)	202	131	225	290	157	203	226

Note: fuel costs include infrastructure costs except for biodiesel where sufficient infrastructure is assumed to be in place already.

To test the impact of typical ship operating characteristics on the most cost-optimal fuel type and engine, this study estimates 2050 total cost of ownership (TCO) for three ship prototypes: a ferry, short-sea vessel and deep-sea container ship. Each ship type is characterised by an estimated annual energy use, onboard energy storage requirement and engine size.

- Our ferry is modelled after the *Zalophus* passenger boat.[214] Her operating characteristics represent a share of current domestic shipping in the EU.
- Our short-sea vessel is modelled after the *Atlantic Klipper*.[214] Her operating characteristics represent a share of current domestic and intra-EU shipping in the EU.
- Our deep-sea container ship is modelled after the *Emma Maersk*.[214] Her operating characteristics represent a share of outbound EU shipping.

A key sensitivity is the inclusion of LNG infrastructure costs for the LNG/ICE systems. The 2019 study does not include such costs on the account that LNG infrastructure is rapidly deployed in European ports today; a trend that is expected to continue. The rationale is that, like biodiesel, bio-LNG can piggyback on existing infrastructure. However, the amount of bio-LNG consumed by ships in the Gas for Climate 2050 Optimised Gas end state is roughly 7 times the amount of LNG in the BAU scenario. The scale of infrastructure is likely to be quite different between these two scenarios and therefore, additional infrastructure costs are likely to be incurred. We test the effect of decreasing infrastructure cost on the most cost-optimal fuel/engine combination for the three ship prototypes. Infrastructure costs are taken from the Gas for Climate 2019 study.[215]

TCO modelling for 2050 operations leads to the following picture (Table 9).

Table 9. Lowest cost fuel/engine combination in 2050 for three ship prototypes.

	Zalophus	Atlantic Klipper	Emma Maersk

213 T&E, Roadmap to decarbonising European shipping, November 2018

214 Data obtained from Minnehan and Pratt, Practical Application Limits of Fuel Cells and Batteries for Zero Emission Vessels, Sandia National Laboratories, 2017

215 Fuel station costs and distribution infrastructure for LNG in road transport: 26 €/MWh LNG.

Characteristics			
Main engine power	800 kW	2,400 kW	80,100 kW
Tank capacity	0.97 MWh	144 MWh	18,500 MWh
Lowest cost fuel/engine	BEV	BEV	NH_3/FC
TCO (indicative, €/MWh_{out})	159	185	195
Second-best option	Biodiesel/ICE	Biodiesel/ICE	Biodiesel/ICE
Cost increase	+51%	+21%	+8%
Third-best option	Bio-LNG/ICE	NH_3/ICE	NH_3/ICE
Cost increase	+62%	+29%	+11%
Robustness Lowest cost option remains lowest cost option when there is a…	100% decrease in LNG infrastructure cost >400% increase in onboard storage >50% change in annual energy use	95% decrease in LNG infrastructure cost 50% increase in onboard storage 50% change in annual energy use	60% decrease in LNG infrastructure cost 0.67-1.00 range in CAPEX power law, see note below 25% change in annual energy use

Note:

- WACC of 8% assumed
- Investment cost for engines and other onboard equipment scale following a CAPEX power law:

$$CAPEX = CAPEX_{reference} \times \left(\frac{Engine\ capacity}{Capacity_{reference}}\right)^{0.8}$$

- Tank capacity and energy consumption adjusted to specific fuel consumption per fuel/engine combination
- Underlying CAPEX cost estimates from Grahn et al.,[216] Sea\LNG,[217], De Vries,[218] Tjalgegard et al.[219]
- This is a cost modelling exercise only, not a full feasibility assessment

This top-level modelling suggests BEV to be lowest TCO solution for the two smaller ship prototypes. By 2050, the Emma Maersk is best suited for an ammonia fuel cell. Battery electric is not an economic solution, even ignoring the practicality of fitting this much batteries on a ship of her size. The Atlantic Klipper is equipped with just enough batteries for a single trip in this modelling exercise. That seems impractical. Onboard battery capacity can be increased by roughly 50% before other options become more economic. In addition, novel technologies that are currently in development such as smaller, autonomous ships and modular battery replacement to reduce charging time can make the application more viable for a wider range of intra-EU ships in practice.

Biodiesel is the second option for all three ship prototypes. The 2019 study showed that biodiesel will be in high demand in other sectors and from a lowest cost system perspective, the available biodiesel is best deployed elsewhere.

Looking at the different types of fuel/engine combinations, ammonia fuel seems interesting for the longer distances, at the expense of hydrogen and LNG. A sensitivity analysis to equip all three ships with compressed hydrogen (avoiding the relatively expensive liquefaction) did not change this outcome. LNG/ICE is the fourth-best fuel/engine combination for the Emma Maersk prototype, roughly 20% more expensive in €/MWh output compared to ammonia fuel cells. With comparable well-to-wake conversion efficiency between NH_3/FC and LNG/ICE (see Table 8), this operating cost difference is primarily driven by lower primary fuel costs.

The above all describes 2050 as an end state for the shipping sector. With ships invested in today still being part of the 2050 fleet, it is critical to see how (fast) the sector can move towards this end state. Intermediate years may show a very different picture for low carbon ships, and ship owners may choose to invest in different ships because of this. This study uses intermediate cost points for fuels, batteries and conversion efficiencies assess the lowest cost fuel/engine combinations for intermediate years 2030 and 2040.

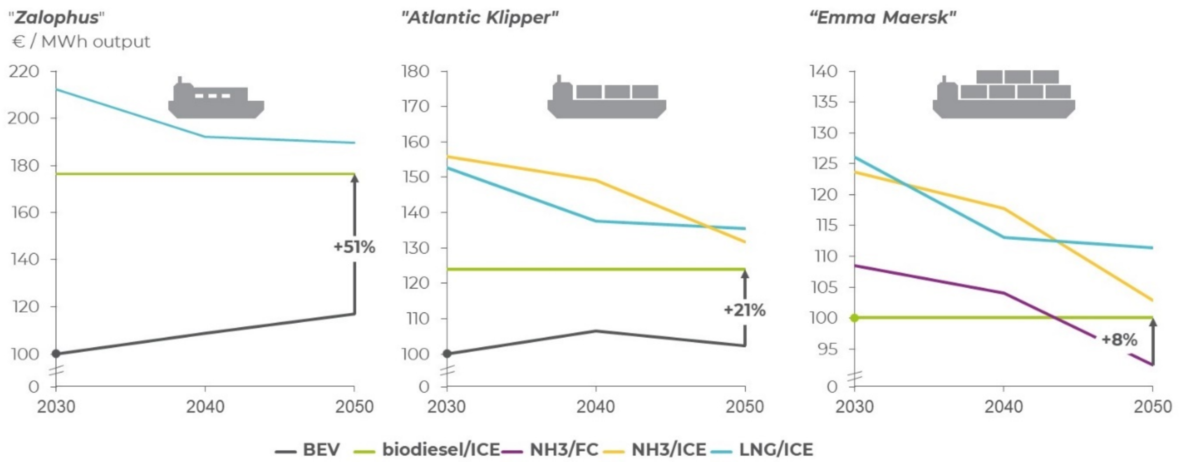
Figure 32 provides an overview of the top-3 lowest cost fuel/engine combinations for the three vessel prototypes under analysis. This overview shows that BEV ships are already the most attractive option for low carbon shipping in 2030 for both the short-sea and ferry prototypes, limiting any accelerated write-off or retrofit costs to achieve the 2050 end state. For the

216 Grahn et al., Cost-effective choices of marine fuels under stringent carbon dioxide targets, Chalmers University, 2013
217 SEA\LNH, LNG as a marine fuel – the investment opportunity
218 De Vries, Safe and effective application of ammonia as a marine fuel, TU Delft, 2019
219 Tjalgegard et al., Electrofuels – a possibility for shipping in a low carbon future?, Chalmers University, 2015

deep see container ship, it seems biodiesel is the lowest cost option for 2030 and 2040, only to be overtaken by ammonia fuel cell technology in the final decade towards 2050. With limited biodiesel availability in the European system as described above, ship owners may look at the second option early, which is ammonia fuel cell or LNG. This could mean that even for this ship prototype, already in 2030, the most attractive option is the same as for 2050, limiting accelerated write-off or expensive retrofitting.

Figure 33 shows the robustness of these outcomes over time when decreasing the share of infrastructure cost burden on LNG/ICE. It shows that LNG infrastructure costs have a large influence on what ultimately is the lowest cost fuel/engine combination. LNG/ICE can climb from the number 4 position to the number 1 position depending on the share of infrastructural costs included in TCO for the Atlantic Klipper and Emma Maersk. For the Atlantic Klipper, Figure 33 shows BEV to be a robust outcome in terms of lowest cost of operating from 2030 onwards. For the Emma Maersk this outcome is less robust over the same decades. Indeed, when including 50% of LNG infrastructure, the comparison between LNG/ICE and NH_3/FC is a close call. Reducing infrastructure costs further makes LNG/ICE the most cost-effective fuel/engine combination.

Figure 32. Lowest TCO fuel/engine combinations for three ship prototypes



Note: Indicative
Source: Guidehouse

Figure 33. Impact on TCO of including decreasing shares of LNG infrastructure costs

Note: Indicative
Source: Guidehouse

Both figures also show that relative TCO differences per fuel/engine combination are reduced with increasing ship size. The robustness of the lowest cost fuel/engine combination of deep-sea ships is lowest of the three vessel prototypes. At the same time, this ship prototype represents the largest share of total energy consumption of the shipping sector.[220] It is therefore key to gain a better understanding of these differences and how this may affect fuel consumption for the shipping sector.

This top-level analysis provides indications that after BEV, bio-LNG might not always be the most economic pathway to decarbonise the shipping sector. Instead, ammonia-based propulsion systems could be the way forward, depending on the size and operating conditions of the ship in question. This conclusion seems robust under varying underlying assumptions such as energy consumption level, onboard energy storage capacity and the effect of economies of scale to capital requirements. However, this was a limited exercise on three shipping prototypes and on costs alone. Indeed, other factors besides operating costs, such as safety of operation, NO_x emissions, toxicity and perception thereof, are critical for large-scale deployment. The global sector is undergoing a transformation to lower emitting fuels and witnesses aggressive cost reductions of low carbon technologies. More study is required on technology development, safety, capital costs and total operating costs for a wide range of ships to gain understanding on where the shipping sector ultimately might be heading.

220 The 2019 study showed that over half of all energy is consumed in outbound-EU shipping movements.

6. Power Decarbonisation Pathways

Key Takeaways

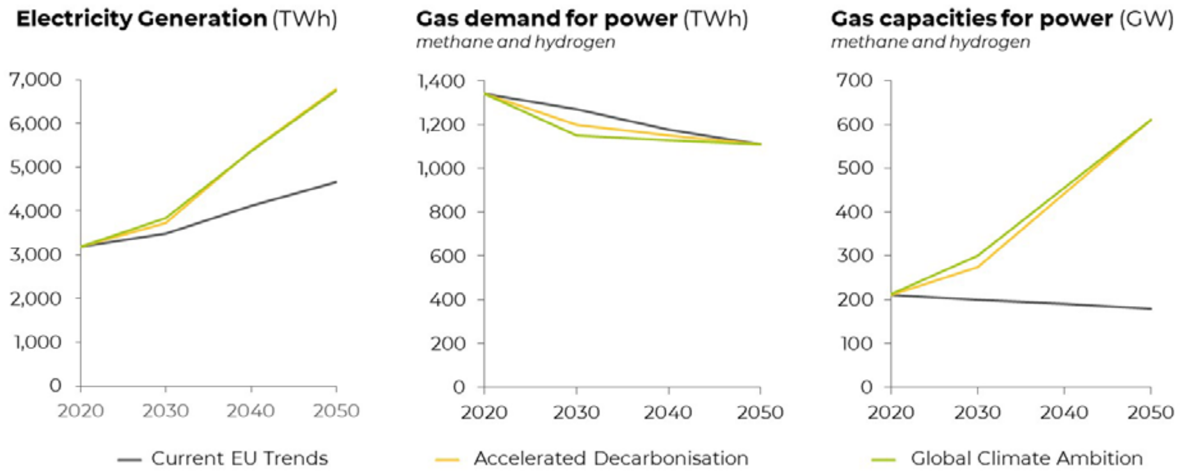
- In the Current EU Trends Pathway, we expect limited electrification efforts and ongoing efficiency improvements to result in stable electricity demand towards 2030. When renewable electricity shares in the EU increase towards 55% by 2030, the result is a reduction in gas demand and other fuels. Installed gas-fired power generation capacities remain stable around 220 GW. No power generation based on hydrogen is developed until 2030. Current EU trends make it unlikely that we reach the Gas for Climate 2050 end state in terms of total electricity use and generation and, consequently, installed capacities of gas-fired dispatchable generation.

- In the Accelerated Decarbonisation Pathway, electricity demand starts to increase well before 2030 and renewable electricity shares reach 60%-70% by 2030. Gas-fired power plant capacity increases from around 220 GW in 2020 to 275 GW by 2030 due to increasing shares of intermittent renewable electricity and the phaseout of coal-based power production. Hydrogen-fired power plants will still have a small role by 2030. To meet the Gas for Climate 2050 end state, further scale-up is needed after 2030, in which installed capacities of gas-fired dispatchable generation running on hydrogen or methane should increase to over 600 GW.

- In the Global Climate Action Pathway, electricity demand grows even faster. Breakthrough technologies in buildings, industry, and power increase electricity demand by 2030 and electricity generation will be partly covered by hydrogen-fired power plants by 2030. Electricity generation increases from about 3,200 TWh in 2020 to over 3,800 TWh in 2030 and installed capacity of gas-fired power increase from about 200 GW in 2020 to 300 GW in 2030, out of which 25 GW uses hydrogen.

o reach electrification levels as foreseen in the Gas for Climate 2050 end state, electrification must ramp-up as soon as ossible. The following scenarios describe electrification efforts and the role of gas in the power sector:

Figure 34. Overview of Power sector pathways



Source: Guidehouse

6.1 Introduction

6.1.1 Current situation

Further electrification is essential to achieving a net-zero emissions EU energy system. In the last 30 years, electricity generation in the EU increased from 2,594 TWh in 1990 to 3,287 TWh in 2018, representing around 20% of total final energy demand.[221] The share of electricity from renewable sources in gross electricity consumption almost doubled in the past decade, from 16.9% in 2008 to 32.1% in 2018.[222] Since 1990, the emissions intensity of electricity dropped by 44% from 0.524 kgCO_2/kWh in 1990 to 0.296 kgCO_2/kWh in 2016.[223] While production from renewables strongly increased, and production from coal, lignite, nuclear, and oil gradually decreased, electricity generation from gases increased from below 10% in 1990 to around 20% in the last decade (Figure 35).[224] At this moment, around 660 TWh of electricity (20%) is produced out of around 1,330 TWh of gas, from which 1,160 TWh is natural gas and derived gases, and 170 TWh is biogas. The installed capacity of gas-fired power plants is 220 GW.

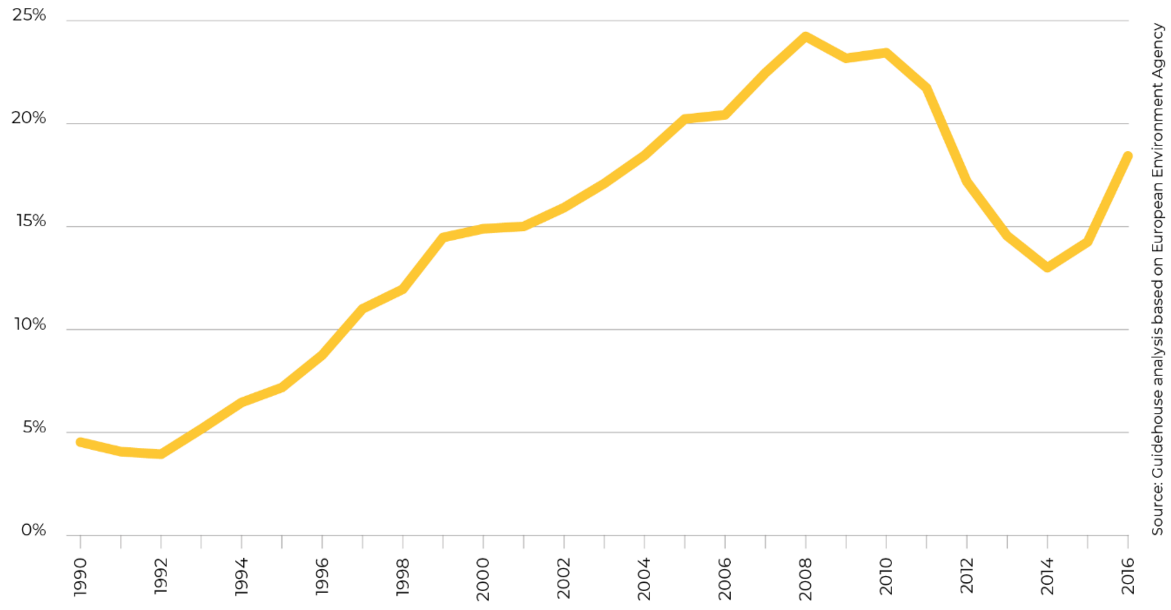
221 Gross electricity production-based Eurostat, “Supply, transformation and consumption of electricity [nrg_cb_e],”

222 Eurostat Statistics Explained, “Renewable Energy Statistics,” Eurostat, https://ec.europa.eu/eurostat/statistics-explained/index.php/Renewable_energy_statistics.

223 European Environment Agency, “Overview of Electricity Production and Use in Europe,” https://www.eea.europa.eu/data-and-maps/indicators/overview-of-the-electricity-production-2/assessment-4.

224 European Environment Agency, “Overview of Electricity Production and Use in Europe.”

Figure 35. Share of natural and derived gases in gross electricity generation



Source: European Environment Agency

6.1.2 Gas for Climate 2050 Optimised Gas end state

Decarbonisation of the EU power system implies fundamental changes in the way electricity will be generated, stored, and transported. Wind and solar will be the mainstay of future EU renewable electricity production, mainly in the form of direct available sustainable electricity, but also via dedicated solutions producing green hydrogen. However, the intermittency of these renewable electricity generation sources, with peaks regularly exceeding total demand, requires smarter electricity grids, the widespread introduction of flexibility measures, and higher levels of (seasonal) storage and dispatachable generation capacity. Increasing electrification, from around 20% now to over 50% of final energy demand by 2050, also requires upgrading electricity distribution and transmission infrastructure to meet increases in demand response technologies, batteries, and pumped hydro storage will provide some of the flexibility needed in the electricity system. Batteries are suitable for storage over several days, but an integrated solution between the energy systems for electricity and gas, using power-to-gas and gas-to-power is highly desirable, as gas is more suitable for large-scale, long-term storage.

Renewable and low carbon gas like green hydrogen, stored in salt caverns and used in efficient gas-fired power plants can provide dispatchable capacity in periods of insufficient renewable electricity supply.[225] Existing gas transmission and distribution infrastructures can be used efficiently in large parts of the EU and have a remaining technical lifetime far beyond 2050. The Gas for Climate 2019 study included a power system analysis and concluded that providing dispatchable power is one of the four areas where renewable gases add substantial societal benefits.[226]

To produce renewable gases like green hydrogen, more renewable electricity should be produced than directly needed. Even though in an integrated energy system energy needs to be converted twice (electricity to hydrogen to electricity), additional renewable electricity generation for green hydrogen production is the most cost-efficient solution to deal with intermittent energy supply and seasonal fluctuations in energy demand.

In the Gas for Climate 2050 Optimised Gas end state, electricity generation from gas decreases slightly from around 660 TWh in 2020 to around 500 TWh in 2050. However, installed capacity increases from around 220 GW to around 600 GW by 2050. The need for dispatchable power generation is in line with the Eurelectric's Decarbonisation Scenarios, with around 500 GW

225 With high shares of intermittent renewable electricity, the capacity factor of gas-fired power plants will be low. Because of the low full load hours, post combustion CCS on gas-fired power plants is not a suitable option because of the capital expenses involved in developing CCS installations.

226 Other areas include space heating of buildings, high temperature heating in industry, and long distance, heavy duty transport. In view of the low full load hours, biomethane- and hydrogen-fired power plants are preferred over solid biomass power plant because of the higher CAPEX of the latter.

gas-fired and nuclear power plants.[227] Where generation is mainly based on natural gas, in 2050 this will be a mix of hydrogen (490 GW) and biomethane (120 GW). As gas-fired power is solely used as firm dispatchable power generation by 2050, full load hours decrease but the required capacity increases significantly. Because of the reduced running hours, newly constructed methane- and hydrogen-fired power plants will be primarily open cycle gas turbines (OCGTs). OCGTs have a relatively low CAPEX compared the higher efficiency combined cycle gas turbines.

6.2 Electricity pathway under current EU climate and energy policies

Conclusion Current EU Trends

In the Current EU Trends Pathway, we expect limited electrification efforts and ongoing efficiency improvements to result in stable electricity demand towards 2030. When renewable electricity shares in the EU increase towards 55% by 2030, the result is a reduction in gas demand and other fuels. Installed gas-fired power generation capacities remain stable around 220 GW, thereby reducing full load hours of gas-fired power plants. No power generation based on hydrogen is developed until 2030. Current EU trends make it unlikely that we reach the Gas for Climate 2050 end state in terms of total electricity use and generation and, consequently installed capacities of gas-fired dispatchable generation.

6.2.1 EU policies

The main policy drivers for decarbonising the power sector are RED and EU ETS.

The revised RED (RED II) established a new binding renewable energy target for 2030 of at least 32% for the EU, with a clause for possible upwards revision by 2023.[228] Member states were required to submit 10-year National Energy and Climate Plans (NECPs) by the end of 2019, outlining how they will meet the new 2030 targets for renewable energy and energy efficiency. Increasing the share of renewable electricity in the power mix is essential in meeting the overall renewable energy targets.

Large-scale electricity generation has been part of the EU ETS from its start in 2005. Price levels increased from early 2018 to above €20/tCO_2 in 2019.[229] This is a driver for the development of renewable and low carbon electricity generation and for a shift from coal-based towards natural gas-based electricity generation.

6.2.2 Regional differences today

As set in the RED, the overall EU target for renewable energy (for all energy carriers) in 2020 was translated into national renewable energy targets, taking into account the country's starting point and overall potential for renewables, ranging from 10% in Malta to 49% in Sweden.[230] No country-specific targets have been specified in the RED II for 2030.

The 2016 share of electricity from renewable sources significantly varies between member states, ranging from below 10% in countries such as Luxembourg, Hungary, and Malta, to over 60% in countries like Denmark, Austria, and Sweden.[231] The share of natural gas and derived gases differ per country, ranging from below 10% in countries such as Bulgaria, Finland, France, and Slovakia to above 40% in countries such as Ireland, Italy, Latvia, and the Netherlands.

227 Eurelectric, 2018. Decarbonisation Pathways – Full study results. Slide 53. Available at: https://www.eurelectric.org/decarbonisation-pathways/

228 Energy, "Renewable energy directive," European Commission https://ec.europa.eu/energy/en/topics/renewable-energy/renewable-energy-directive/overview

229 Carbon Price Viewer, "EUA Price," Sandbag: Smarter Climate Policy, https://sandbag.org.uk/carbon-price-viewer/.

230 EU Science Hub, "Renewable Energy – Recast to 2030 (RED II)," European Commission, https://ec.europa.eu/jrc/en/jec/renewable-energy-recast-2030-red-ii.

231 European Environment Agency, "Overview of Electricity Production and Use in Europe," https://www.eea.europa.eu/data-and-maps/indicators/overview-of-the-electricity-production-2/assessment-4.

6.2.3 Pathway towards 2050

The Current EU Trends Pathway for power is based on the recently published EUCO scenario,[232] which is designed to achieve a 32% share of renewable energy in gross final energy consumption and a 32.5% energy efficiency target in the EU.[233][234] Overall, the EUCO scenario reaches a 45.6% emission reduction in 2030 compared to 1990.

- The demand for electricity slightly increases to 3,400 TWh–3,500 TWh by 2030. While the share of electricity in final energy demand increases because of electrification, this is offset by energy efficiency.
- The share of renewable electricity is increasing from 35.7% in 2020 to 44.8% in 2025 and to 55.5% in 2030. The electricity generation from gas-fired power plants reduces only slightly to around 500 TWh–600 TWh until 2025 (because of phasing out nuclear in Belgium, for example). After 2025, generation from gas-fired power plants in the EUCO scenarios reduces sharply to around 375 TWh. In the Current EU Trends Pathway, we assume a more moderate reduction from 600 TWh in 2020 to 550 TWh in 2030.
- As a result, demand for gas in power plants declines slightly, from 1,340 TWh in 2020 to around 1,270 TWh in 2030. The installed capacity stays around 200 GW. This illustrates that gas-fired power plants are increasingly providing peak load capacity rather than baseload capacity, which reduces their capacity factor.
- Coal is still part of the electricity mix by 2030, but generation and capacity are strongly reduced.
- No power generation from hydrogen is expected until 2030.

Current EU trends make it unlikely that we reach the Gas for Climate 2050 end state in terms of total electricity use and generation and, consequently, installed capacities of gas-fired dispatchable generation. To reach the potential for renewable electricity identified in the 2050 Optimised Gas scenario, electrification and electricity generation should increase steeply after 2030. Increasing electricity generation should parallel the further decarbonisation of the power sector. Due to increasing shares of intermittent renewable electricity, the installed capacity of gas-fired power plants should increase from about 200 GW in 2030 to over 600 GW in 2050. Demand for gas remains stable at 1,000 TWh–1,200 TWh, but a transition from fossil gases to renewable and low carbon gases is required.

232 "The EUCO3232.5 scenario reflects a cost-efficient pathway to achieve the 2030 targets in the context of existing and enhanced policy measures. Building on the Reference scenario, the modelling represents the additional policies and measures at national level in a stylised manner, applied equally across all EU Member States. (…) These projections neither prejudge Member States' policy choices nor any additional measures they might include in their National Energy and Climate Plans."

233 Energy, "EUCO Scenarios," European Commission, https://ec.europa.eu/energy/en/data-analysis/energy-modelling/euco-scenarios

234 European Commission, Technical Note: Results of the EUCO3232.5 Scenario on Member States, 2019, https://ec.europa.eu/energy/sites/ener/files/technical_note_on_the_euco3232_final_14062019.pdf.

6.3 Accelerated Decarbonisation Pathway – Electricity

Conclusion Accelerated Decarbonisation

To realise strong emission reductions in the next decades (as envisioned in the Accelerated Decarbonisation Pathway) actions are required on all possible levels:

- The major contribution to emission reductions in the power sector should come from the increased deployment of renewable electricity generation to 60%-70% of total electricity generation in 2030 and the full decarbonisation of the power sector around 2045.
- Other measures are needed to reduce emissions. Accelerating the coal phaseout to realise emission reductions (in addition to those resulting from renewable electricity deployment) as well as deployment of blue hydrogen for power generation, can put Europe on a steep emission reduction curve.

In the Accelerated Decarbonisation Pathway, 60%-70% of electricity in 2030 will be generated by renewables. The remaining 30%-40% will be primarily covered by nuclear (around 20%) and gas (around 15%). Gas demand in the power sector amounts to around 1,200 TWh by 2030. While gas demand is reducing slightly, gas-fired power plant capacity increases from around 220 GW in 2020 to 275 GW by 2030 due to increasing shares of intermittent renewable electricity and the phaseout of coal-based power production. Initially, there will be an increase in installed capacity of power plants running on methane. However, because of the switch towards hydrogen in the longer term, these new plants should be hydrogen-ready.

6.3.1 The Green Deal's implications for power

The goal of the EU Green Deal is to get on track towards climate neutrality in 2050. It aims to increase the EU emission reduction target to 55% by 2030. If the European Commission's long-term strategy is successful, 53% of Europe's energy needs would be met by electricity by 2050.[235] Accelerated decarbonisation can be achieved through various means—energy efficiency targets, renewable energy targets, lower ETS cap—but an increased level of electrification and faster deployment of renewables is likely part of the equation.[236] In Eurelectric's Decarbonisation Scenarios and in the European Commission's pathway presented in *A Clean Planet for All*, the power sector should fully decarbonise and reach 0 g/kWh by 2045.[237] As such, renewable electricity shares of up to 60%-70% by 2030 are required. In addition, a phaseout of coal-fired power plants can strengthen emission reductions in the short term. Increased electrification, faster deployment of renewables, and phaseout of coal-fired electricity generation increases the need for flexibility, including dispatchable generation, to deal with variability.

6.3.2 Pathway towards 2050 Optimised Gas scenario

Compared to the Current EU Trends Pathway, the Accelerated Decarbonisation Pathway involves an increase of electricity demand as result of increased electrification efforts. Electricity generation and resulting gas demand are obtained from the 2030 snapshots in the European Commission's long-term vision in its *A Clean Planet for All*. To achieve a decarbonised power sector by 2040, the renewable electricity share should be around 60%-65% by 2030 (as compared to 55% in the EUCO scenario). Like the Current EU Trends Pathway, the Accelerated Decarbonisation Pathway projects a larger role for gas in 2030, partly because of phasing out coal-fired electricity generation and partly because of required dispatchable generation capacity for increased shares of renewables.

- The demand for electricity increases from around 3,200 TWh in 2020 towards 3,700 TWh in 2030.
- Electricity generation from gas-fired power plants reduces. As a result, gas demand reduces from 1,340 TWh in 2020 to around 1,200 TWh in 2030. Installed capacities increase from 220 GW in 2020 to 275 GW in 2030.

235 Dave Keating, "Europe Needs to Double Electricity Share to Meet Climate Goals – EU Official," *Euractive*, November 7, 2019, https://www.euractiv.com/section/electricity/news/europe-needs-to-double-electricity-share-to-meet-climate-goals-eu-official/.

236 Climate Action, "2050 Long-Term Strategy," European Commission, https://ec.europa.eu/clima/policies/strategies/2050_en.

237 Eurelectric, 2018. Decarbonisation Pathways – Full study results. Slide 53. Available at: https://www.eurelectric.org/decarbonisation-pathways/

- Some of the additional capacity build towards 2030 can be based on hydrogen.

To reach the 2050 Optimised Gas Pathway, electrification and electricity generation should continue to increase steeply after 2030. Due to increasing shares of intermittent renewable electricity, the installed capacity of gas-fired dispatchable generation should increase from about 275 GW in 2030 to 600 GW in 2050. Demand for gas remains at levels ranging from 1,000 TWh–1,200 TWh. A transition from fossil gases to renewable and low carbon gases is also required.

6.3.3 Critical timeline

In the Accelerated Decarbonisation Pathway, 60%-70% of electricity in 2030 will be generated by renewables. The remaining 30%-40% will be primarily covered by nuclear (around 20%) and gas (around 15%). Gas demand in the power sector amounts to around 1,200 TWh by 2030. While gas demand is reducing slightly, gas-fired power plant capacity increases from around 220 GW in 2020 to 275 GW by 2030 due to increasing shares of intermittent renewable electricity and the phaseout of coal-based power production. Initially, there will be an increase in installed capacity of power plants running on methane. However, because of the switch towards hydrogen in the longer term, these new plants should be hydrogen-ready.

Plants located in industrial clusters where blue hydrogen will be developed will be the first to move from methane to hydrogen in the coming decade. More solitary gas-fired power plants outside hydrogen clusters have three options:

1. Delay shifting from methane to hydrogen until they get connected to the hydrogen network or the existing gas grid connection is converted to hydrogen
2. Get natural gas through their existing grid connection and produce blue hydrogen onsite[238]
3. Get a private company to invest in a dedicated hydrogen pipe to supply them

Developing new capacity requires overall energy system planning that considers the future layout and build-up of dedicated hydrogen networks and the future development of regional electricity demand.

Accelerating decarbonisation of power generation through coal phaseout and blue hydrogen deployment

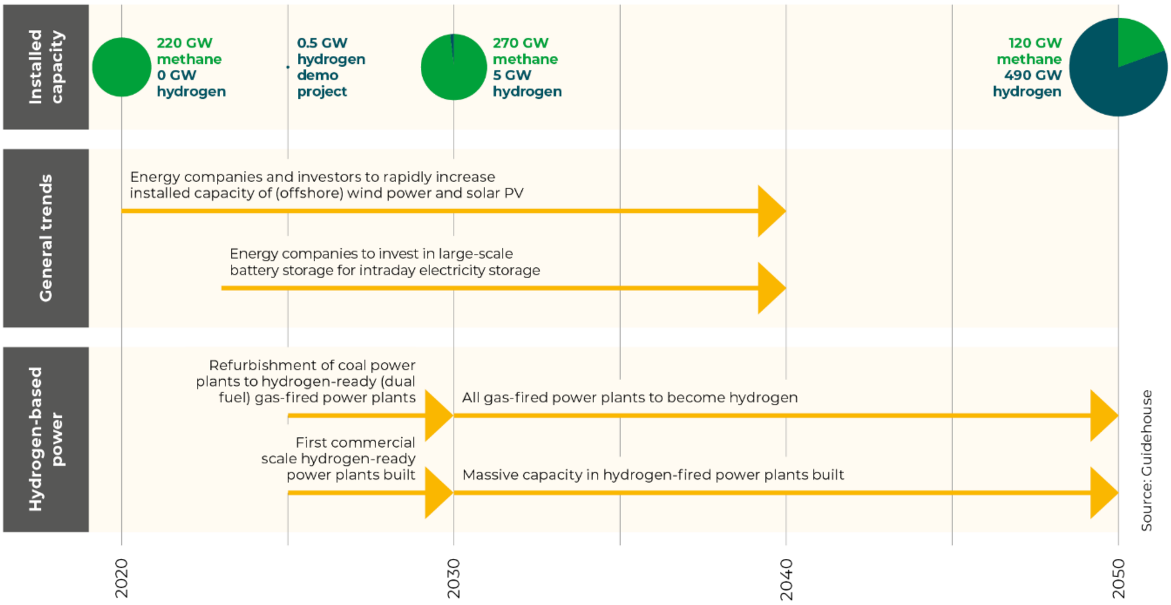
Actions on all levels are required to realise strong emission reductions in the next decades. In the power sector, the increased deployment of renewable electricity generation should be a major contributor to emission reductions. Energy companies and investors must rapidly increase capacity of (offshore) wind power and solar PV. Other measures are needed to reduce emissions in the short term as well, thus positively affecting the cumulative CO_2 emissions. Member states should accelerate a coal phaseout and deploy renewable and low carbon gases (like biomethane and hydrogen) to realise emission reductions on top of those from renewable electricity deployment. The combination could put Europe on a steep emission reduction curve. Stimulating the development of blue hydrogen production and its use for dispatchable power generation will also foster short-term emission reductions without interfering with the deployment of renewables.

Ensure economic feasibility of gas-fired backup generation

Energy companies should invest in large-scale battery storage for intraday electricity storage. However, long-term seasonal storage is needed as well. Given the large role of hydrogen in the future power system, commercialisation of new hydrogen plants and refurbishment of existing coal and natural gas-fired plants to make them hydrogen-ready is needed (Figure 36). In the short term, commercialisation leads to additional capacity based on hydrogen around 2030 and enables additional scale-up towards 2050. While nowadays gas-fired power plants are also providing baseload electricity, their role will shift to providing dispatchable backup generation towards 2050. Because of quickly reducing full load hours, mechanisms should be in place that support the availability of dispatchable electricity for system stability.

238 Also referred to as pre-combustion CCS.

Figure 36. Critical timeline power generation



6.3.4 Policy recommendations

Ensuring continuous power supply with gas-fired power plants

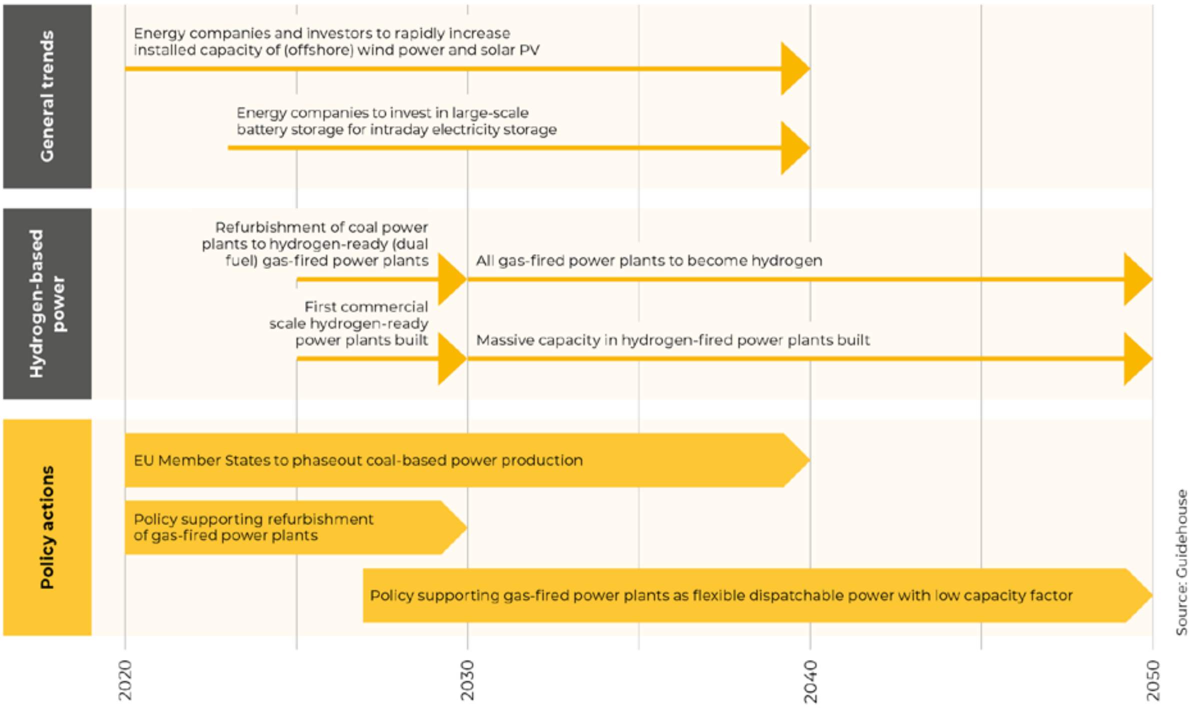
Electrifying the energy system is essential to achieving a net-zero emissions EU energy system. The share of electricity from renewable sources is already increasing; however, the decarbonisation of the EU power system suggests fundamental changes in the way electricity will be generated, stored, and transported. With wind and solar as the mainstay of future EU renewable electricity production, the intermittency of these renewable electricity generation sources requires smarter electricity grids, widespread introduction of flexibility measures, and higher levels of (seasonal) storage and dispatchable capacity. Increasing electrification also requires upgrading electricity distribution and transmission infrastructure to meet demand increase, and to cope with more frequent, less predictable, and higher peaks on the supply side. However, demand response technologies, batteries, and pumped hydro storage will provide some of the flexibility needed in the electricity system for a short period. The Gas for Climate 2050 Optimised Gas end state sees a role for gas-fired backup generation for longer term storage with a limited number of cycles.

In the power sector, the major contribution to emission reductions should come from the increased deployment of renewable electricity generation. The Accelerated Decarbonisation Pathway suggests an increase of renewable electricity generation to 60%-70% of total electricity generation in 2030 and full decarbonisation of the power sector around 2045.

Next to the increased deployment of renewable electricity, the pathway suggests that accelerating a coal phaseout and deploying renewable and low carbon gases (like biomethane and hydrogen) can realise additional emission reductions. Especially for deploying renewable and low carbon gases in the power sector, the commercialisation of new hydrogen plants and refurbishment of existing natural gas-fired plants is needed already around 2030, enabling further scale-up towards 2050.

Compared to current EU policies, the Accelerated Decarbonisation Pathway needs the refurbishment of gas-fired power plants to hydrogen and commercial-scale hydrogen-fired power plants in the coming decade. This requires policies to support the refurbishment of gas-fired power plants to hydrogen and policies supporting biomethane- and hydrogen-fired power plants as dispatchable generation.

Figure 37. Critical timeline and policy actions for power



6.4 Global Climate Action Pathway

Conclusion Global Climate Action

In the Global Climate Action Pathway, electricity demand grows even faster, and hydrogen-based power production emerges before 2030. Breakthrough technologies in buildings, industry, and power increase electricity demand by 2030. Electricity generation will be partly covered by hydrogen-fired power plants by 2030. Electricity generation increases from about 3,200 TWh in 2020 to over 3,800 TWh in 2030 and installed capacity of gas-fired power increase from about 200 GW in 2020 to 300 GW in 2030, out of which around 10 GW is hydrogen.

6.4.1 Pathway towards 2050

In the Global Climate Action Pathway, we envision even more electrification efforts up until 2030, resulting in higher uptake of electric vehicles, heat pumps, and more. Similar to the Accelerated Decarbonisation Pathway, by 2030, the Global Climate Action Pathway reaches a 60%-70% renewable electricity share of total electricity. Higher electricity demand combined with a coal phaseout by 2030 results in additional gas-fired capacity and gas demand towards 2030. Part of the additional demand is covered by retrofitted and newly built hydrogen-fired power plants.[239] Stimulating the development of hydrogen production and its use for dispatchable power generation will foster short-term emission reductions without interfering with the deployment of renewables.

- The demand for electricity increases from around 3,200 TWh in 2020 towards over 3,800 TWh in 2030.

239 Because gas-fired power plants are increasingly used for backup generation only, open cycle gas turbines (OCGT) are preferable because of their lower CAPEX compared to combined cycle gas turbines (CCGT). While CCGT plants have higher efficiencies, OCGT plants are more economical because of the low full load hours.

- Electricity generation from gas-fired power plants reduces. As a result, gas demand reduces from 1,340 TWh in 2020 to around 1,150 TWh in 2030. Capacity increases from 200 GW in 2020 to 300 GW in 2030.
- Of the additional capacity built towards 2030, around 10 GW is based on hydrogen.

After 2030, electrification and electricity generation increase steeply. Due to increasing shares of intermittent renewable electricity, the installed capacity of gas-fired power plants should increase from about 300 GW in 2030 to 500 GW in 2050. Demand for gas remains at levels ranging from 1,000 TWh–1,200 TWh. A transition from fossil gases to renewable and low carbon gases is required as well. The installed capacity of gas-fired dispatchable generation is lower than in the Accelerated Decarbonisation Pathway because of the expected breakthrough developments in batteries, making them suitable for energy storage over longer periods of time.

7. Gas Infrastructure Pathways

Key Takeaways

- Gas infrastructure ensures the reliability and flexibility of the EU energy system.
- Under current EU climate and energy policies, gas grids will continue to transport, store and distribute decreasing quantities of natural gas in coming decades plus increasing quantities of biomethane and hydrogen.
- The Accelerated Decarbonisation Pathway would lead to the creation of a dedicated European Hydrogen Backbone infrastructure shortly after 2030, largely based on existing gas infrastructure.
- In the Accelerated Decarbonisation Pathway biomethane will gradually replace natural gas in the parts of the transmission grid that will not be converted to hydrogen. And gas distribution networks would increasingly be used to distribute biomethane to older buildings.
- Blending natural gas with a certain amount of hydrogen can—depending on region and customer base—facilitate a short-term market for hydrogen suppliers. Yet the hydrogen volumes needed to reach a net-zero emission energy system in 2050 will require a dedicated hydrogen infrastructure around 2030.

7.1 Introduction

Gas infrastructure plays a key role in the current EU energy system, connecting European gas production sites, onshore pipeline, and LNG import entry points to demand centres across Europe. Gas transported through gas infrastructure provides a flexible, storable, and cost-efficient form of energy. Gas assets are an important tool in achieving a net-zero carbon economy by transporting renewable and low carbon gases. Most importantly, the large and flexible capacity of the gas grid can realise strong synergies with large-scale intermittent renewable power generation.

Transitioning towards a net-zero carbon economy will impact the role of gas grids as they exist today. This chapter outlines several pathways describing this transition at various speeds, related to future market conditions and policies to stimulate developments.

The Gas for Climate 2050 study conclusions

The Gas for Climate 2019 report drew important conclusions on the role of infrastructure in a net-zero carbon economy in 2050:

- The Optimised Gas scenario, based on electricity, (bio)methane, and hydrogen energy carriers, results in €19 billion of lower energy infrastructure costs compared to the Minimal Gas scenario annually by 2050 due to prolonged utilisation of gas infrastructure. In addition, much higher additional cost savings associated with the Optimised Gas scenario are achieved elsewhere in the energy system in energy end use and supply.
- Existing gas infrastructure will have a valuable role in transporting, storing, and distributing renewable and low carbon gases.
- The existing transmission grid will be used for inter-regional and cross-border transport of hydrogen and mainly intra-regional transport of renewable methane in parallel.
- The existing gas distribution grid will be used to distribute biomethane to buildings, mainly for heating during cold periods. This leads to high net system cost savings per cubic metre of gas.
- Quantities of gas transported in 2050 decrease compared to current volumes though transported peak demand will decrease much slower.

This pathway analysis focuses on how gas infrastructures will support the pathways to the Gas for Climate 2050 Optimised Gas end state.

7.2 The role of gas grids in Europe today[240]

Gas infrastructure plays and will continue to play a key role in the current EU energy system. It connects gas production sites in Europe, as well as pipeline import points on the EU borders and LNG terminals with demand centres all over Europe (including natural, renewable, and decarbonised gas production). Gas infrastructure is currently used to transport and distribute 25% of EU's primary energy consumption, or about 4,500 TWh (NCV) equalling about 425 bcm of natural gas.[241] As the energy transition advances, gas infrastructure will provide transportation and storage capacity for renewable energy in the form of gaseous energy carriers. The European gas infrastructure will make the overall European energy system more flexible and more resilient.

Gas transported through gas infrastructure provides a flexible, storable form of energy that is mainly used for building and industrial heating, gas-fired power plants, and chemical production. About 25% of current natural gas is from EU sources, the rest is imported through large gas import pipelines from Russia, Norway, and North Africa (including Algeria), and LNG imports from the rest of the world.[242] The grids foster security of supply and diversification of sources.

Long-distance gas transport occurs through large diameter transmission lines operated at high pressure (usually from 40 up to 100 bar, depending on the country). This network is used to import gas from outside the EU and to interconnect EU member states' national gas networks. Medium pressure pipelines (between 8 and 40 bar) are used to distribute gas to a

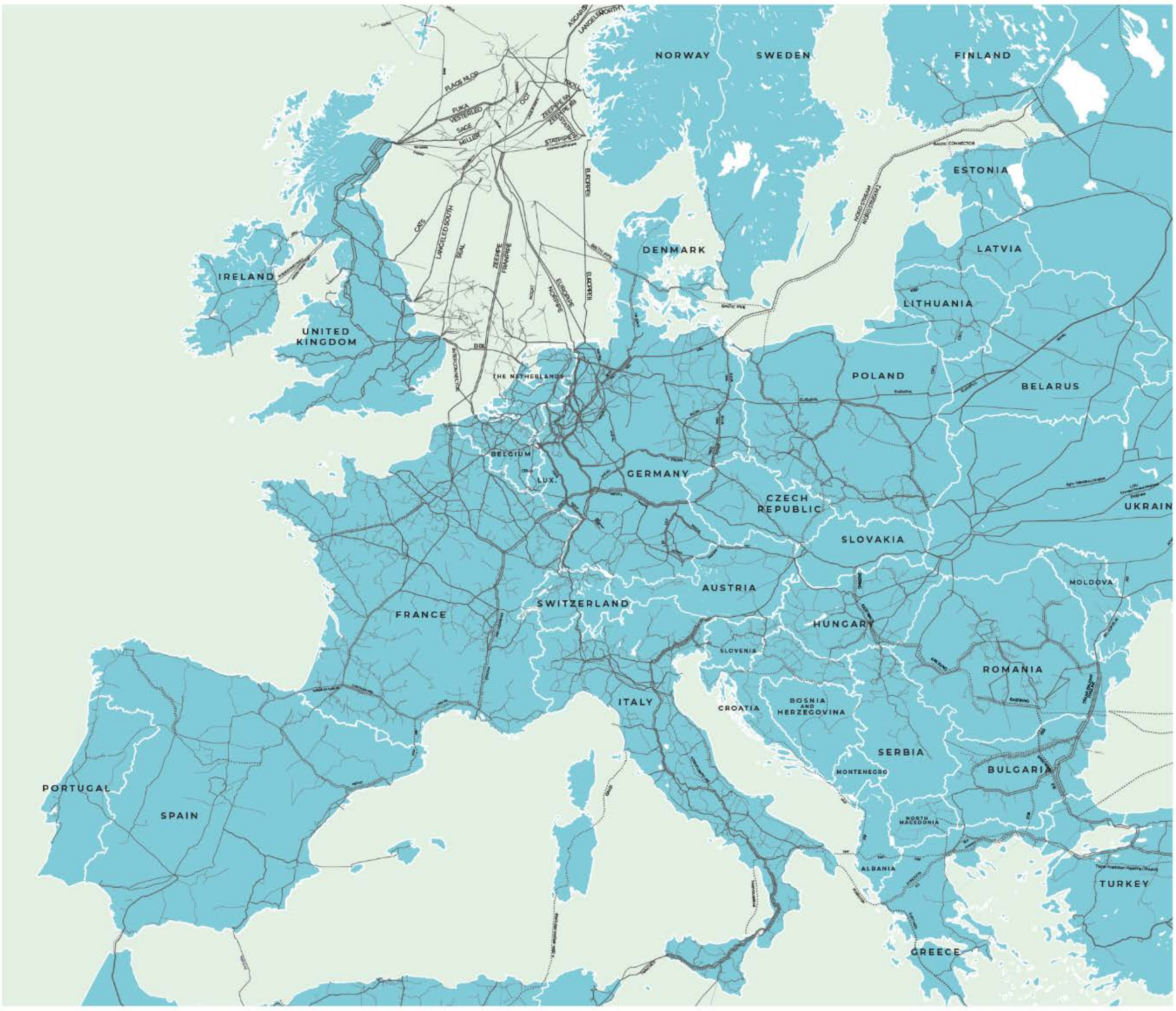
240 Section taken from Navigant, Gas for Climate, 2019

241 Quantity reported in net calorific value, equalling about 5,000 TWh in gross calorific value. Eurostat, Natural gas supply statistics, gross inland consumption of natural gas in 2018. Total EU energy consumption in 2017 was 1675 Mtoe or around 19,000 TWh.

242 Eurostat, Natural gas supply statistics, https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Natural_gas_supply_statistics&oldid=447636#Supply_structure, 2020

dense network of low pressure distribution grids (up to 16 bar) delivering gas to end consumers.[243] The transmission network consists of about 260,000 km of high pressure transmission pipelines and medium pressure pipelines operated by around 45 TSOs. Figure 38 displays this network.

Figure 38. Natural gas transmission networks in Europe[244]



Source: ENTSOG

Many transmission lines consist of multiple parallel pipelines to provide enough transmission capacity. The more refined network of mainly low pressure and some medium pressure networks consists of about 1.4 million km of pipelines operated mainly by distribution system operators (DSOs).

Gas storage is required to ensure the security of energy supply and to enable the system to deal with significant variations in gas demand between summer and winter. Storage provides flexibility to react on short term variations in demand, including short term power demand peaks where gas-fired power plants may be needed on short notice, e.g. due to a lack of wind or solar generation. Regional gas storages are available, mostly connected to high or medium pressure transmission systems. In some regions, small gas storages are directly linked to the low pressure grid.

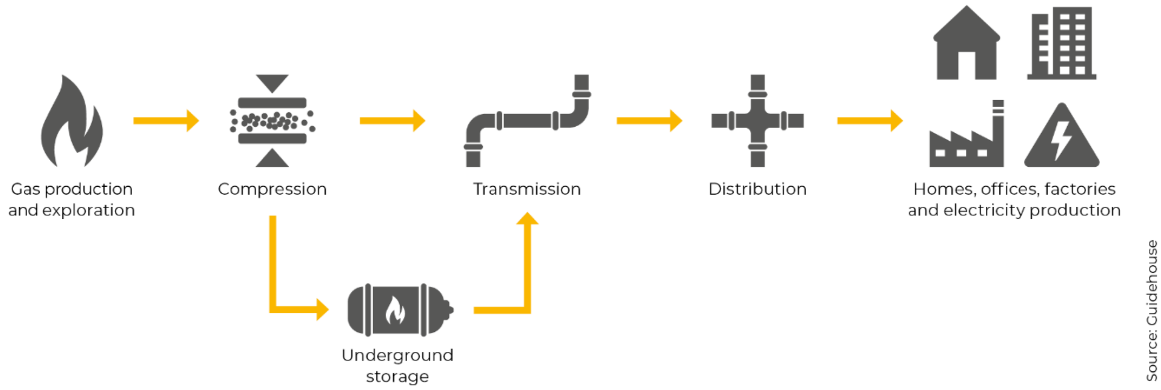
Compressor stations ensure the required pressure to transport gas over long distances in gas grids. Typically, the EU gas transmission network requires one compressor station per 200 km of pipeline. Import pipelines transport gas over long distances at a high pressure of 100 to 200 bar. These pipelines can require a compressor station for typically every 100 km.

243 What low, medium, and high mean varies depending on the country

244 ENTSOG, see https://transparency.entsog.eu/

Import pipelines constitute a small share of the total EU gas transmission infrastructure. In some cases, like for subsea pipelines, compressor stations are not available. These pipelines are operated at a high inlet pressure of up to 220 bar.[245]

Figure 39. Structure of the gas infrastructure



In 2020, most natural gas is used to produce industrial heat, provide feedstock to the chemical industry, heat buildings, and produce flexible electricity in gas-fired power plants. Energy demand fluctuates strongly between seasons and even over a single day; the annual demand shows significant variations. The gas transport system can cope with these fluctuations with its large and flexible pipeline and gas compression capacities and underground gas storage sites and regasification plants across the European grid. The gas grid can deal with low overall transported volumes that currently occur during summertime. There is no minimum technical threshold under which the gas network can no longer be operated.

7.3 Gas infrastructure pathway under current EU policies

Conclusion Current EU Trends

The current gas infrastructure plays an important role in the EU energy system. Under current policies, gas demand will decrease to about 4,200 TWh or around 395 bcm by 2030, however gas peak demand would only decrease slightly, and the use of natural gas will remain an important part of the future energy mix.

Current capacities of the gas grid are sufficient to meet current and future demand; however, there can be regional considerations for transmission and distribution grid expansion, such as gas source diversification or a local switch from coal to natural gas.

To accommodate a slowly growing role of hydrogen in industries and transport up to 2030, local point-to-point pipelines and transport via trucks will be sufficient. In some cases, hydrogen could be blended into gas distribution grids to avoid the need for dedicated pipeline development.

This section describes a gas infrastructure pathway under current EU climate and energy policies.

245 The Nordstream pipeline has an inlet pressure of 220 bar, see http://www.gazprom.com/projects/nord-stream/

7.3.1 Existing EU policies relevant for gas infrastructure

All EU policies as described in previous sections will impact the future consumption and supply of natural gas, biomethane, and hydrogen and will impact the way in which gas infrastructure will be used in the future. In addition to this, some EU policies specifically cover natural gas, most notably the gas directive[246] and the security of supply directive.[247]

EU gas directive
The EU gas directive covers all gas grids in EU member states and between member states and third countries. The most important elements are the EU-rules for the gas market, such as unbundling network and production, third-party access, non-discriminatory tariffs, and requirements for transparency.

Security of Supply Directive
Requires the European Network for Transmission System Operators for Gas (ENTSOG) to perform an EU-wide gas supply and infrastructure disruption simulation to identify major supply risks for the EU.[248] In addition, specific policies have been put forward to ensure that EU-wide infrastructure develops in alignment with specific priorities in security of supply such as defined in the Connecting Europe Facility[249] (CEF) and the underlying Trans-European Network Energy programme (TEN-E).[250]

Existing gas transmission pipelines transport natural gas and a small quantity of biomethane. Differences in gas quality are linked to the origin of the gas. The EU is working towards a more harmonised gas quality across Europe in collaboration with the European Association for the Streamlining of Energy Exchange (EASEE-gas).[251]

The EU Energy Union strategy aims to remove technical and regulatory barriers to energy flowing freely throughout the EU. This includes diversification of gas supply sources and routes. Transmission operators must secure bidirectionality on all cross-border capacity, unless exempted. The Energy Union also stimulates international collaboration in the Energy Infrastructure forum and in high level groups. Development of the infrastructure is facilitated via TEN-E and Projects of Common Interest (PCIs).[252]

246 2009/73/EC, Concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC

247 2017/1938, Concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010

248 ec.europa.eu

249 1316/2013, Establishing the Connecting Europe Facility, amending Regulation (EU) No 913/2010 and repealing Regulations (EC) No 680/2007 and (EC) No 67/2010

250 347/2013, On guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009

251 https://ec.europa.eu/energy/en/topics/markets-and-consumers/wholesale-market/gas-quality-harmonisation

252 European Commission, www.europa.ec (2019)

CEF Energy, TEN-E, and PCIs

CEF Energy is an EU funding instrument to promote growth, jobs, and competitiveness in energy infrastructure investment at the European level and promote the development of TEN-E. Four priority gas corridors have been identified that should deliver more gas supply diversification and security of supply to member states. In addition, corridors will be developed that tackle short term integration between electricity and gas, smart grids to integrate renewable energy, cross-border CO_2 grids, and electricity highways to connect renewable energy hotspots to demand sites and storage potential. PCIs facilitate development of cross-border infrastructures, including projects that enable countries to diversify their supply via LNG imported into the EU.

Source: Source: ec.europa.eu

The EU has undertaken efforts to enhance energy security by enabling the import of LNG to diversify gas supply. Interconnections will be predominantly bidirectional to allow flows from both directions to be used as gas source. This is especially relevant since LNG imports typically come from different coastal areas in Europe (Figure 40) compared to the imports of gas via mainly onshore pipelines in southern and eastern EU.

As the gas diversification strategy results in more imported LNG to be regasified and supplied to the grid, the direct use of LNG will also grow, mainly in maritime and truck transport. Growth of the direct demand for LNG is not expected to have a large impact on gas pipeline infrastructure, as maritime use will be close to shore, allowing the majority of LNG demand to be supplied via ships, partially using the same infrastructure as for LNG imports.[253] For LNG demand in trucks, the LNG can be transported through supply trucks, or through local liquefaction of biomethane.

253 Trinomics, The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets, 2018

Figure 40. Map of Europe showing the available LNG import locations in the EU[254]

Source: GIIGNL Annual Report (2019)

Current policies do not explicitly stimulate the development of large international hydrogen pipelines or backbones. The existing international hydrogen connections have been developed and are owned by private companies, such as Air Liquide, which connects industrial clusters in North France, Belgium, and the Netherlands.

7.3.2 Gas infrastructure Pathway under current EU policies

This section describes how gas infrastructure may develop towards 2050 under current EU climate, energy and energy infrastructure policies.

7.3.2.1 Gas Infrastructure during 2020-2030

To understand the impact of the current EU 2030 policy package on the required EU gas infrastructure, we base ourselves on the plans made by the individual member states to meet the EU 2030 energy strategy targets, as set out in their NECPs[255] and captured in the *TYNDP National Trends* scenario.[256] According to the TYNDP scenario, the gas demand in the EU will drop towards 2030 by around 12% to around 4,200 TWh, resulting in a few percent drops in required peak capacity for gas transmission.[257] Biomethane production under current EU policies could grow to about 200 TWh by 2030, or about 4% of the total gas demand. A large part of the biomethane will be fed into the distribution grids and are not expected to impact the available capacity of the grids

254 GIIGNL Annual Report (2019).

255 ENTSOG, ENTSOE, TYNDP 2020 Scenario report & TYNDP 2020 Scenario Methodology Report 2019.

256 Regulation (EU) 347/2013 requires that the ENTSOs use scenarios for their respective Ten-Year Network Development Plans (TYNDPs). Final NECPs have been published in December 2019, which will result in a revised *TYNDP National Trends* scenario by February 2020. Although this scenario will not reach the COP21 climate target of full CO_2 emission reduction, it provides a best possible effort to forecast the impact of current policies on the 2030 gas infrastructure.

257 ENTSOG, ENTSOE, TYNDP 2020 Scenario report.

Regional market developments could result in local need for capacity increase due to the need to import more gas into Europe due to indigenous EU production decrease, e.g. the upcoming production stop in the Groningen field and growing regional demand due to coal-to-gas fuel switching in the power sector and switching from oil-based building heating to gas-based, mainly in Eastern Europe.

Under current policies, hydrogen will not play a major role in the European energy system in 2030, even in scenarios that have a large share of hydrogen in the final gas mix.[258,259,260] The development of blue hydrogen mainly replaces already existing grey hydrogen production from natural gas and results only in a local need for CO_2 transport infrastructure. In the period 2020 to 2030, green hydrogen production is tested in demonstration projects, closely linked to existing hydrogen assets or use. If required, in some regions, the already existing hydrogen infrastructure could be used to distribute hydrogen, such as in France, Belgium, Germany, and the Netherlands. Regions with CO_2 storage locations and industries with hydrogen production and demand (such as along the North Sea coast and in the southern part of Europe) will be the first to develop new hydrogen infrastructures that service users beyond existing industrial markets.

Up to 2030, the available capacity of the current gas infrastructure will be sufficient to meet the natural gas and biomethane demand. Little impact is foreseen due to biomethane or hydrogen production and demand developments. Regional developments can introduce local capacity constraints. However, it will be possible to incorporate these organically as part of the regular grid planning cycle.

7.3.2.2 Gas Infrastructure during 2030-2050

Current EU climate and energy policies are unlikely to deliver a net-zero emissions energy system by 2050. In this scenario, natural gas consumption would somewhat decline over time, but it may be likely that by 2050 still significant volumes of natural gas would be used. This means that gas infrastructure would continue to carry natural gas. In this scenario, the use of hydrogen mostly will be limited to industries, which means that there will be limited need for dedicated hydrogen networks and that infrastructure will be limited to mainly local, point-to-point connections. Biomethane injection to grids would increase, but likely far below the EU biomethane potential. A decrease in natural gas volumes combined with a limited uptake of both hydrogen and biomethane can mean that between 2030 and 2050 parts of existing European gas grids may become obsolete and would be mothballed or decommissioned. This could be particularly true for routes with multiple parallel pipelines.

258 Navigant, Gas for Climate, 2019.

259 Trinomics, The role of Trans-European gas infrastructure in the light of the 2050 decarbonisation targets, 2018.

260 International Energy Agency, The future of hydrogen, 2019.

7.4 Accelerated decarbonisation pathway – gas infrastructure

Conclusion Accelerated Decarbonisation

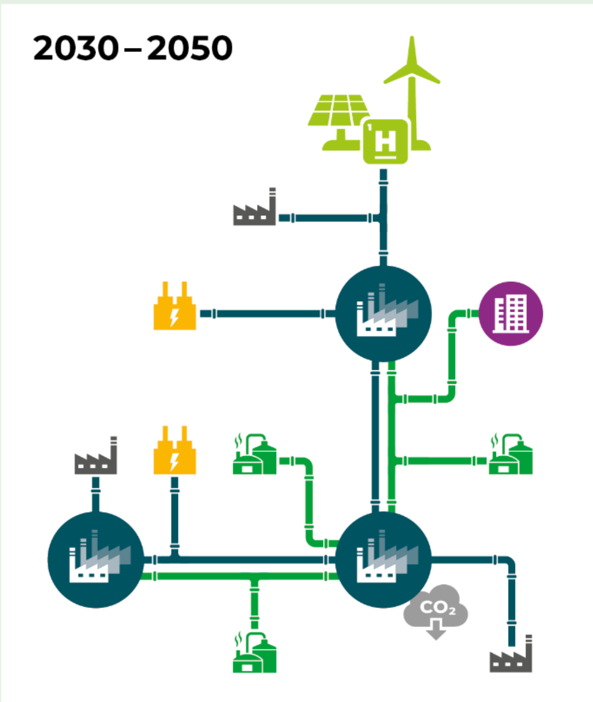
Natural gas consumption will decrease more rapidly while renewable and low carbon gases are scaled up rapidly in parallel. No gas grid capacity issues are foreseen in the current gas infrastructure. Biomethane and hydrogen make up 10% of total gas consumption in the EU by 2030, followed by a rapid and accelerated scale-up between 2030 and 2050.

Up to 2030, gas infrastructure will be mainly used to transport, store and distribute natural gas, yet volumes of grid-injected biomethane and hydrogen will increase gradually. Biomethane is injected mainly in low and medium pressure grids yet also in higher pressure grids. Biomethane will often be used locally to heat buildings with gas connections yet will increasingly also be transported to different regions and across borders through transmission grids, facilitated by reverse-flow technology. Between 2040 and 2050 a notable production of power to methane could be expected, using biogenic CO2 captured in large biogas digesters and green hydrogen produced onsite. This methane will be injected in existing gas grids. Up to 2030 only a limited quantity of hydrogen will flow through gas grids, often blended with natural gas. Hydrogen will initially mainly be used in industrial clusters that already use hydrogen today. Around 2030, the scale-up of green and blue hydrogen and its increased consumption in industrial sites outside industrial clusters will require the creation of dedicated regional or national hydrogen infrastructures. During the 2030s, the regional and national backbones are connected to create a European hydrogen backbone infrastructure. This hydrogen infrastructure will mainly be based on retrofitting existing natural gas transmission pipelines to dedicated hydrogen pipelines. For this reason, decommissioning of natural gas transmission pipelines should be avoided. Dedicated hydrogen storage facilities will be developed.

The figure below provides a snapshot of how gas infrastructure would develop in 2030 and 2040 in the Accelerated Decarbonisation Pathway.

Figure 41. Gas infrastructure in 2030 and 2040

- Renewable electricity generation, feeding into electrolysers to produce green hydrogen. Green hydrogen can be blended in gas infrastructure, yet for larger projects, dedicated pipelines are foreseen which will be merged into larger hydrogen backbone infrastructure during the 2030s.
- Natural gas infrastructure with injected biomethane
- Hydrogen infrastructure
- Industry cluster using natural gas
- Industry cluster using and producing hydrogen
- Heating of buildings
- Solitary industry connected to industry clusters or green hydrogen production plants
- Biogas plants feeding into the natural gas grid



- Increased share of renewable electricity generation for the production of green hydrogen. Green hydrogen feeds directly into the hydrogen backbone infrastructure.
- Methane infrastructure
- Hydrogen infrastructure
- Industry cluster using and producing hydrogen
- Hybrid heating of buildings
- Solitary industry connected to industry clusters or the hydrogen infrastructure.
- Biogas plants feeding into the methane grid or into industry clusters for the production of blue hydrogen (thereby creating negative emissions)
- Power plants using hydrogen to produce dispatchable power

Source: Guidehouse

The rest of this section will detail the Accelerated Decarbonisation Pathway, describing first the situation today, followed by developments in each of the three decades up to 2050.

7.4.1 EU Green Deal for infrastructure

One of the policy areas for the EU Green Deal is clean energy, which covers both the transition of the energy sector and energy infrastructure aspects. For infrastructure specifically, the Green Deal aims to promote cross-border and regional cooperation to achieve benefits of the clean energy transition at affordable prices. It aims to review the existing regulatory framework for energy infrastructure, including the TEN-E Regulation to ensure consistency with the climate neutrality objective. And it aims to facilitate development of new infrastructures, including hydrogen networks or CCS and CCU, and energy storage, as well as enabling sector integration.[261] It is unclear what the scope and direction of these policy reviews will be.

In the Accelerated Decarbonisation Pathway, we assume that infrastructure developments will follow demand and supply as resulting from implementation of the EU Green Deal. Based on the pathway we will indicate what policy action can be taken to support timely and cost-efficient developments in the gas grids.

7.4.1.1 Gas infrastructure developments from 2020–2030

Gas infrastructure used predominantly to transport and store natural gas

During the coming decade, Europe's gas infrastructure will continue to help transport and store natural gas. For most of Europe, existing gas infrastructure is fit for its purpose and no grid expansion is required. The exception is in Central and Eastern Europe, where a coal phaseout driven by increased EU ETS prices is expected to result in an increase of renewable electricity and in gas-fired power plants to provide flexible capacity. This shift may require extensions to gas grids in those countries, especially since gas infrastructure in Central and Eastern Europe typically has a lower granularity compared to Western Europe.

Increased injection of biomethane to gas grids

The production of biomethane in the Accelerated Decarbonisation Pathway increases gradually to a quantity of about 370 TWh (or about 35 bcm) by 2030. Most of this by far will be produced via anaerobic digestion, which takes place in relatively small installations often dispersed throughout rural locations. Biomethane can be blended with natural gas without requiring any gas grid modifications. In many cases, grid injection will take place in low or medium pressure distribution grids, simply because biomethane plants will want to inject into the nearest possible gas pipeline, which will often be distribution grids. If relatively large biomethane plants feed into small gas distribution pipes in areas with little local gas demand, there will be a need to ensure that biomethane can flow upwards towards medium or even high pressure grids using reverse-flow technology. This is a marked change compared to current flows, which are always from high to medium to low pressure grids. Reverse flow is in the process of being implemented today[262] and requires limited investments. Biomethane grid connection costs can be significant when small biomethane plants are connected to grids. It would be cost-optimal to build larger biomethane plants as close as possible to gas grids.

As described in the text box on page **Error! Bookmark not defined.**, most biomethane production can be expected to be injected into gas grids. The larger the size of biomethane plants, the greater the share of the total biomethane potential that could be injected to gas grids. However, a share of remote biogas digesters located far from gas grids is unlikely to produce biomethane that can be injected into gas grids. Alternative solutions need to be developed, such as biomethane transport as bio-CNG or bio-LNG via truck to local fuel stations.

In addition to digestion-based biomethane, several large 200 MW biomass-to-biomethane gasification plants can be expected to be built at port locations or in forested regions close to existing gas grids. These plants deliver biomethane at a pressure of 40 bar, meaning it can easily be injected in medium or high pressure gas grids.

Existing gas distribution networks used to supply biomethane to existing buildings.

Gas infrastructure will continue to be used to distribute gas to heat buildings. Gradually, due to increased building insulation, gas demand for buildings will decrease. In parallel, natural gas will be gradually replaced by biomethane. Also, gradually gas boilers could be replaced by hybrid heat pumps, as described in section 3.3 above. Navigant expects that by 2050 each EU

261 European Commission, The EU Green Deal, https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf, 2019

262 For example, the ONTRAS gas network in Germany already has six reverse-flow facilities installed. See: https://www.ontras.com/en/company/ontras-going-green/our-projects/. Also, GRTgaz operates several reverse-flow facilities such as Pouzauges and Noyal-Pontivy

member states can produce sufficient biomethane to meet demand in existing buildings with existing gas grid connections. This means that distribution grids in 2050 will be used for biomethane, and regional transport pipes are required to transport biomethane supply in the agricultural regions to the cities.

Blue hydrogen in industrial clusters use existing H_2 networks and new CO_2 pipelines.

In the coming decade, the existing production of grey hydrogen will turn blue by adding carbon capture to existing hydrogen production assets, transporting captured CO_2 to storage locations. Existing grey hydrogen is produced and consumed mostly in large industrial clusters in north western Europe where the majority of hydrogen is consumed today. These clusters are well-connected to existing gas grids. Hydrogen production either takes place onsite (e.g. at refineries) or production and industrial consumption is connected through dedicated, privately operated hydrogen networks. These pipelines have a limited capacity yet can be used to transport blue hydrogen within industrial clusters up to 2030, with natural gas being delivered via the existing gas grids like today. Large industrial hydrogen projects will require a solution to transport CO_2 to storage locations. In cases where industrial clusters are located close to empty gas fields below seabeds, e.g. below the North Sea, it makes sense to construct new, dedicated CO_2 pipes. A possibly costlier alternative could be to transport CO_2 per ship to storage locations.

Industrial clusters close to below seabed CO_2 storage locations are favourable options for future additional blue hydrogen capacity. This could result in hydrogen hubs that could feed a future hydrogen backbone infrastructure to supply hydrogen to other clusters, power plants, and truck transport.

Green hydrogen supplied to local customers could require regional hydrogen pipelines

Green hydrogen developments will initially be clustered to specific regions because of low cost production (mainly solar power in south of EU and offshore wind at the North Sea).

Up to 2030, the initial large-scale green hydrogen projects are likely to produce quantities that can be absorbed as feedstock and as sources of heat in local industries and as a road fuel in transport. In cases where quantities of green hydrogen are small, it may make sense to blend hydrogen with natural gas (see below for a more detailed description of blending). In cases where larger quantities of green hydrogen are produced, local or regional dedicated hydrogen pipelines may be needed to get green hydrogen to customers. Such singular dedicated hydrogen pipelines would also be required to supply hydrogen to standalone industrial steel or chemical plants with a substantial natural investment cycle. Ideally, these pipelines would be based on existing gas pipelines, especially in cases where parallel gas pipelines exist. As described in the Gas for Climate 2019 study, provided current pressure levels are not significantly increased, carbon steel pipelines could carry hydrogen without suffering from hydrogen embrittlement or hydrogen stress cracking. The conversion of existing gas pipelines to enable hydrogen transport is inexpensive.

Around 2030, it is expected that a larger scale-up of green hydrogen will require the gradual construction of a European Hydrogen Backbone infrastructure, primarily based on existing gas infrastructure.

Hydrogen blending in gas grids mainly a solution for initial green hydrogen production

Blending hydrogen in the existing gas grid is often considered as a way to quickly scale-up hydrogen supply, while limiting the need for hydrogen pipeline and end-user investments. Studies report blending percentages of between 5% and 20% to be technically feasible in current grids with minimal investments.[263] Blending can also connect biomethane production sites with small percentages of hydrogen to the grid, e.g. pyro gasification units. However, the actual feasibility of blending depends on the hydrogen tolerance at end-uses, including the ability to deal with varying blends. Moving to higher blending percentages, changes need to be made to the infrastructure and typically also to the end-user equipment (e.g. different burners).

The expected scale-up of blue hydrogen production at industrial clusters to replace replaces existing grey does not involve blending but does dedicated point-to-point hydrogen transport and dedicated CO_2-transport. Blending part of the blue hydrogen produced at industrial clusters could be considered when supply is greater than demand. Green hydrogen would up to 2030 mainly be used locally and regionally and blending hydrogen in gas distribution grids may be an effective temporary solution during the 2020s. The creation of a hydrogen Guarantee of Origin system would ensure that the value of blended green hydrogen blending could be marketed.

263 GRTgaz et al. Technical and economic conditions for injecting hydrogen into natural gas networks, http://www.grtgaz.com/fileadmin/plaquettes/en/2019/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf, 2019 & Melaina, Antonio and Penev, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, https://www.nrel.gov/docs/fy13osti/51995.pdf, 2013.

Storing hydrogen

Storing hydrogen in (partially) empty gas fields needs further investigation; amongst other issues to be studied, it could result in an unpredictable blend of methane and hydrogen. Salt caverns or containers are technically suitable for storage. To contain the same amount of stored energy, the pressure needs to be higher, which will not always be possible.

7.4.2 Gas infrastructure developments from 2030 to 2050

National hydrogen infrastructures emerge, joined into a European Hydrogen Backbone

Around 2030, hydrogen demand will have accelerated, and an increasing number of industrial clusters will use more and more quantities of hydrogen. This will initially occur in industrial clusters in north western Europe, and then will move to other parts of the continent as well. Green hydrogen supply will start to ramp-up fast. This leads to a need to connect industrial clusters with large new green hydrogen production locations close to large offshore wind power production and at large solar PV production locations. Also, gradually more standalone industrial sites will move to hydrogen in line with their natural investment cycle. This means that around or shortly after 2030 regional or national hydrogen backbone infrastructures start to emerge. The planning of these infrastructures should start in the early 2020s. Around 2035 these national backbones will increasingly be connected into a European Hydrogen Backbone, which would be completed by around 2040. Also, larger dedicated hydrogen storage facilities in salt caverns will start to be created around 2030.

Initial research shows that long-distance networks could be repurposed to create regional "backbones for a hydrogen transmission system"[264 265] and that natural gas distribution grids can be repurposed to distribute hydrogen; however, the costs and effort will be regionally dependent.[266, 267] The steps required to convert an existing distribution grid to hydrogen are well described in the proposal for the City of Leeds in the H21 report.[268]

By 2050, just over 1,700 TWh would flow through the hydrogen grid. The transport of this quantity of hydrogen requires more pipeline capacity per unit of energy compared to natural gas because hydrogen has about three times more volume than methane. On the other hand, hydrogen flows much faster through gas grids. The net effect of both elements is that hydrogen requires about 20% more capacity per unit of energy compared to natural gas. For example, 160 bcm of hydrogen requires gas pipelines that can transport just over 190 bcm of natural gas equivalent.

To repurpose part of the EU gas grid towards hydrogen, regulatory frameworks should be adjusted to consider hydrogen-ready components when TSOs extend the existing grid or apply for re-investment projects. A general political recognition of the existing gas infrastructure to efficiently decarbonise a part of the European economy is advisable.

Most biomethane flows through distribution and transmission grids

All new biomethane gasification plants are connected to gas grids. All new digestion-based biomethane plants will initially be connected to gas grids as well. Once most of the locations close to gas grids are occupied, locations further away will need to have a much larger size to still be able to be connected. It may still be possible to cost-effectively connect large digesters and biomethane plants that produce up to 3,000 m^3/hr to gas grids even if they are located more than 10 km away from gas grids. This means that the extent to which the full EU biomethane potential can be produced and injected into gas grids can depend on whether the biomethane sector manages to increase the overall size of biomethane plants, especially in countries where the gas grid is less dense, such as Denmark. It is also worthwhile to explore whether biomethane pipeline costs could be decreased. The text box that follows explores the quantity of EU-produced biomethane that could be transported through gas grids. Determining this precisely would require a detailed analysis of how the dispersed EU biomethane (feedstock) potential compares to the topology of gas grids in most relevant EU member states. In our Accelerated Decarbonisation

264 See e.g. Gasunie / TenneT, "Phase II - Pathways to 2050, A joint follow-up study by Gasunie and TenneT of the Infrastructure Outlook 2050", https://www.gasunie.nl/nieuws/gasunie-en-tennet-klimaatdoelstellingen-alleen-haalbaar-met-een-geintegreerd-europees-energiesysteem/$4382/$4383

265 Gasunie (2018): Hydrogen Coalition: concrete plans for a flying start of the hydrogen economy, https://www.gasunie.nl/nieuws/waterstof-coalitie-concrete-plannen-voor-een-vliegende-start-van.

266 Northern Gas Networks (2016). H21 Report, https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.

267 The total costs to make the Dutch distribution networks usable for hydrogen were estimated at 700 million €, resulting in network cost increase per individual household of 10%-50%. Source: (In Dutch) Kiwa (2018). Toekomstbestendige gasdistributienetten, https://www.netbeheernederland.nl/_upload/RadFiles/New/Documents/Kiwa%20-Toekomstbestendige%20gasdistributienetten%20-%20GT170272%20-%202018-07-05%20-D.._.pdf.

268 The H21 report assumes upfront conversion of the distribution network to a hydrogen-ready grid in course of a modernization program that is due to be undertaken anyhow. See Northern Gas Networks (2016). H21 Report, https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf.

Pathway, we assume that 75 bcm biomethane plus an additional 14 bcm of power to methane could be injected into gas grids by 2050.

Box 4. How much of the EU biomethane potential could make its way to Europe's gas grids?

The Gas for Climate 2019 study estimates that by 2050 the EU could produce 95 bcm of biomethane. Up to 30,000 digesters can produce 62 bcm through anaerobic digestion from waste. The agricultural biomass needed for this process is available dispersedly over the about 4.4 million km of the EU land area. How much of this production potential could finds its way to Europe's gas grids?

Answering this question requires a country-specific comparison of the geographically explicit biogas potentials with the topology of national gas grids. This level of analysis was not part of the scope of this study. However, a high level analysis already provides an indication on the large potential of using Europe's gas grids for the transportation of biomethane.

Simplifying the situation

Imagine that the part of the European gas grid that goes through rural areas would run through Europe as one long pipeline. This pipeline consists of the 260,000 km of TSO operated pipelines minus parallel pipelines, plus the share of the 1.4 million km DSO operated grids that runs through rural areas. We assume that 160,000 km out of 260,000 km of the TSO grid consists of parallel pipelines, meaning that there's a total stretch of 100,000 km plus 80,000 km = 180,000 km of TSO pipelines. We also assume that 10% of the DSO grid runs through rural areas where biogas digesters could be connected to it, or 140,000 km. This means that in total a gas pipeline of 180,000 km plus 140,000 km = 320,000 km runs through non-urban areas.

Biomethane plants can be connected to gas grids using small pipes of up to 10 km

The Gas for Climate 2019 conclusion was based on biomethane costs that include 10 km of pipeline to connect biomethane plants to grids. Biomethane plants at the end of the pipe could still source biomass from at least 5 km further away. In our simplified situation, that means that there could be biomethane plants connected from 10 km at either side of the pipe at every part of the 460,000 km long pipeline, sourcing biomass from a distance of 15 km away from the pipeline. The total land area from which the pipeline could source biomethane is 320,000 x 30 = 9.6 million km. The total area in which the gas pipeline could source biomethane is twice as large as the total EU land area, meaning that (in theory) all the EU biomethane potential could be easily connected to gas grids.

The reality is more complex, feasible that 75 bcm could be injected

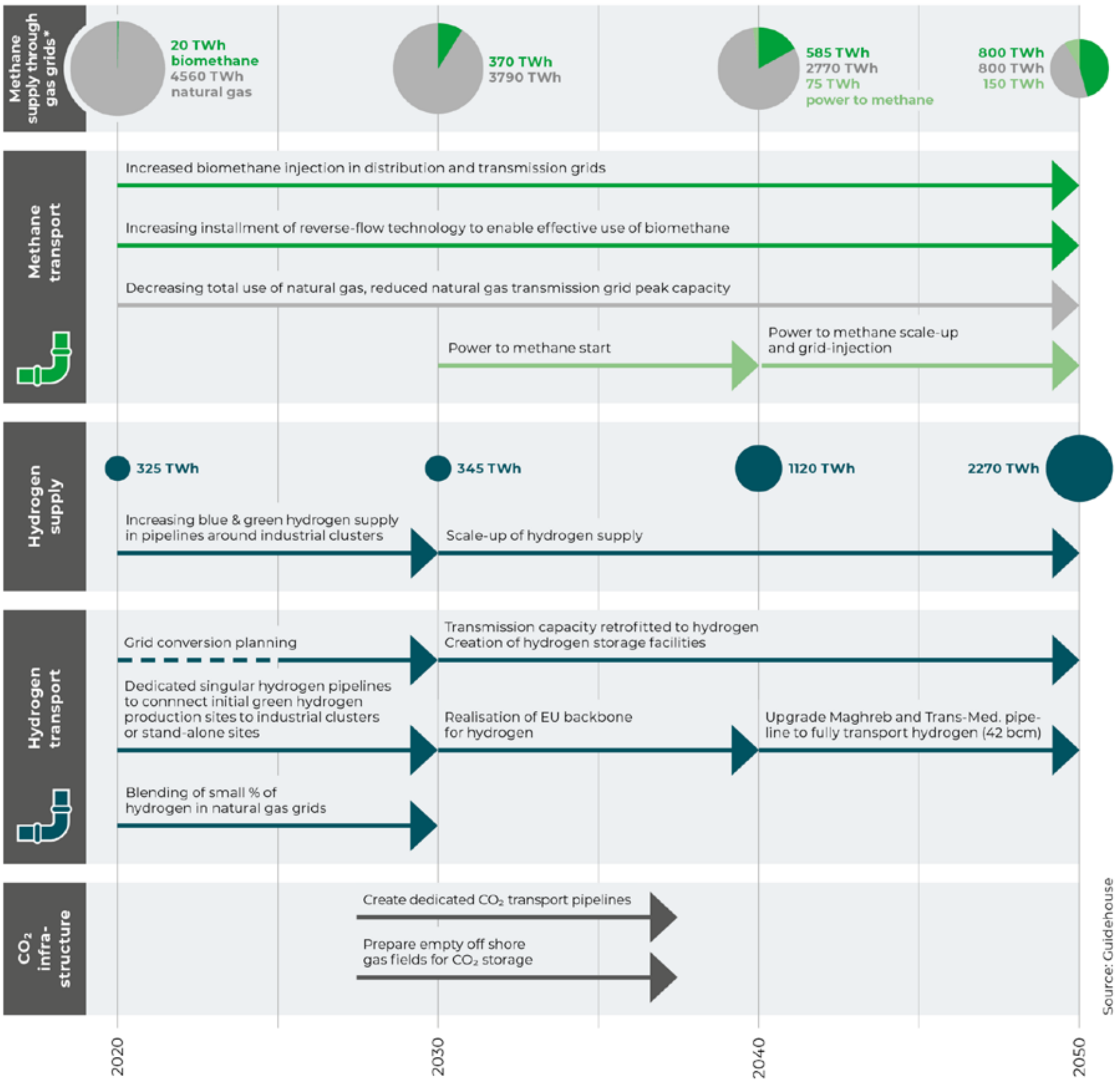
However, the gas grid is not equally dense in all EU member states. The future European Hydrogen Backbone will not consist of parallel TSO pipelines alone but also of converted singular natural gas pipelines, where in the future no biomethane can be connected. On the other hand, biogas digesters could potentially dramatically increase in size, similar to the installations being built in Denmark today that have a biomass sourcing circle of 25 km. Given the large uncertainties, a more conservative approach is fitting and Navigant assumes that one-third of the EU's digestion-based biogas will not be upgraded to biomethane and injected into gas grids. This means that out of the 62 bcm of digestion-based biomethane, 20 bcm will be used locally in CHPs or liquefied to bio-LNG on-farm, whereas 42 bcm makes it to gas grids. In addition, all the 33 bcm of gasification-based biomethane is injected into gas grids. This means that by 2050, a total of 75 bcm of EU-produced biomethane could be injected into gas grids. In addition, 15 bcm of power-to-methane is expected to be produced at locations with gas grid connections, bringing the total of grid-connected renewable methane to 90 bcm or about 950 TWh. Biomethane imports from e.g. Belarus or Ukraine could potentially increase this further.

Gradual phaseout of natural gas means gas grid is split between hydrogen and methane

Substantial quantities of natural gas will remain to be transported through Europe's gas grids, but after 2030 the role for natural gas dwindles rapidly. Industrial consumers and the buildings sector will significantly reduce their natural gas consumption. This means that gas transmission capacity will become increasingly available while gas distribution grids will largely continue to carry gas to existing buildings, initially natural gas but increasingly biomethane to hybrid heating systems. The increase in biomethane and hydrogen does not make up for the reduced natural gas consumption, even though the transport of a unit of hydrogen required more pipeline capacity compared to natural gas. Beyond 2030, a substantial capacity of gas is required to provide dispatchable power. With coal being phased out and the share of wind power and solar PV increasing, gas-fired power plants will run relatively limited hours, yet their peak gas demand is significant.

The figure below provides an overview of most important gas infrastructure developments between 2020 and 2050 in the Accelerated Decarbonisation Pathway.

Figure 42. Critical development in gas infrastructure between 2020 and 2050



** Numbers can be different from biomethane and hydrogen supply figures presented in other sections. Only volumes transported through infrastructure are visualised.*

7.5 Global Climate Action Pathway – gas infrastructure

Conclusion Global Climate Action

Global climate efforts will speed up the transition to biomethane and hydrogen use. Total gas demand will reduce faster than in the Accelerated Decarbonisation Pathway, while supply and demand for biomethane and hydrogen will grow faster.

Around 2030, the hydrogen supply will surpass regional demands and require development of an EU backbone to connect supply to demand further away.

As a result of global developments, large-scale imports of hydrogen and synthetic chemicals and fuels will reduce the capacity required for the transmission grid, compared to the Accelerated Decarbonisation Pathway. However, regional differences will lead to deviating grid requirements.

Global effort to decrease CO_2 emissions will have a strong impact on the cost for green hydrogen and biomethane, through economies of scale that can be realised along the supply chains. The impact of these cost reductions on infrastructure is an increased transition speed compared to the Accelerated Decarbonisation Pathway: the use of natural gas will reduce faster, the share of biomethane in the gas mix will be larger and the demand and production of hydrogen will experience a large scale-up already before 2030.

The supply of green and blue hydrogen around or just after 2030 will be more than can be absorbed by the initial industrial hydrogen clusters. Dedicated hydrogen infrastructure, a hydrogen backbone, will need to be developed around 2030 to facilitate transmission to other demand in the EU.

As a result of global developments, areas around the world with low cost renewable power will have hydrogen available for export to the EU. This is specifically relevant for the import of synthetic chemicals and fuels, such as synthetic kerosene. Large-scale imports of synthetic fuels and chemicals could reduce the hydrogen demand in the EU by over and the required pipeline capacity for hydrogen transmission. The impact on the EU network topology will however greatly depend on regional differences in demand and supply as in the Accelerated Decarbonisation Pathway.

7.6 Hydrogen – methane blending

Blending hydrogen to the existing gas grid is a way to quickly scale-up hydrogen supply, while limiting the need for hydrogen pipeline and end-user investments. Especially in situations where hydrogen is produced in volumes that exceed the demand for hydrogen, this can be a cost-effective solution. Studies report blending percentages of up to between 5% and 20% to be technically feasible in current grids with minimal investments.[269] Blending can also be a solution to connect biomethane production sites with small percentages of hydrogen to the grid, e.g. pyrogasification units. Moving to higher blending percentages, changes need to be made to the infrastructure and typically also to the end-user equipment (e.g. different burners).

269 GRTgaz et al. Technical and economic conditions for injecting hydrogen into natural gas networks, http://www.grtgaz.com/fileadmin/plaquettes/en/2019/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf, 2019 & Melaina, Antonio and Penev, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, https://www.nrel.gov/docs/fy13osti/51995.pdf, 2013.

Existing national regulations for gas quality typically allow a maximum of 2% hydrogen blending, while Austria, Spain, and France allow higher percentages between 2% and 6%. In Germany blending is allowed up to 10%, but only if no CNG filling stations are connected to the infrastructure.[270] In the Netherlands in contrast, only 0.02% blending is allowed.[271]

Hydrogen blending is mostly relevant for the use of hydrogen as a combustion fuel in power and heat generation. For other applications, such as an industrial feedstock or in fuel cells, dedicated hydrogen transport is needed and blending with methane will require separation, which can be costly. For these solutions, dedicated hydrogen infrastructure is a more likely solution, as is also demonstrated by the current existence of dedicated hydrogen pipelines in several industrial clusters, e.g. in the North France/Belgium/Rotterdam, and the Ruhr and Central Germany areas.

As the volume of methane in the gas grids decreases and the volume of hydrogen increases, the blending potential will reach its limit. This means that additional hydrogen will also be transported through dedicated pipelines. Careful control of the blending rates must be established, especially in situations with decentralised and seasonally fluctuating biomethane supply, gas flows going two directions between distribution and transmission grids and intermittent supply of (curtailed) hydrogen from renewable power generation. Because of the international character of gas flows in transmission grids and the standardisation of gas qualities, blending in transmission grids is not expected to exceed a few percentage points of hydrogen.

Blending can be done more flexibly in distribution grids or specific parts of the regional transmission pipes with a limited number of users, linking specific blending rates to the type and needs of the connected users. This also means that regional differences will play a large role in determining the economic and technical feasibility of blending. In regions with relatively small amounts of hydrogen, blending could make more sense. Blending can be more attractive for curtailed power production at low annual full load hours, as it avoids relatively large costs for transport.

7.7 EU natural gas consumption per member state

Table 10 provides the EU's natural gas consumption per member state from 2014–2018. Gross inland consumption illustrates natural gas demand in a country. It refers to the total energy from natural gas needed to satisfy inland consumption and covers final energy consumption from end-use sectors, transmission and distribution losses, and the consumption from the natural gas sector.

Gross inland consumption is the largest in Germany, followed by the UK, Italy, the Netherlands, and France. In 2018, these countries were responsible for about 69% (323.3 bcm of 471.8 bcm) of the total EU natural gas consumption.

Table 10. Gross inland consumption (bcm*) of natural gas in the EU, 2014–2018[272]

Geography	2014	2015	2016	2017	2018
European Union - 28 countries	419.0	436.0	464.8	483.7	471.8
Belgium	15.6	16.8	17.0	17.3	17.7
Bulgaria	2.8	3.0	3.1	3.2	3.0
Czechia	7.5	7.9	8.5	8.7	8.3
Denmark	3.2	3.2	3.2	3.1	3.0
Germany (until 1990 former territory of the FRG)	79.0	81.3	89.1	92.5	85.3
Estonia	0.5	0.5	0.5	0.5	0.5
Ireland	4.4	4.4	5.1	5.3	5.4
Greece	2.9	3.2	4.1	4.9	4.9

270 IEA, The future of hydrogen, https://www.iea.org/reports/the-future-of-hydrogen, 2019.

271 Rijksdienst voor ondernemend Nederland, De eisen voor waterstof in gas, https://www.rvo.nl/onderwerpen/duurzaam-ondernemen/energie-en-milieu-innovaties/gassamenstelling/waterstof-aardgas/de-eisen-voor-waterstof-aardgas, 2020.

272 Eurostat, Gross inland natural gas consumption in the EU, 2019, https://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_103m&lang=en.

Geography	2014	2015	2016	2017	2018
Spain	27.2	28.2	28.8	31.3	31.1
France	36.7	39.8	43.2	43.4	41.5
Croatia	2.4	2.6	2.7	3.1	2.8
Italy	61.9	67.5	70.9	75.2	72.7
Cyprus	0.0	0.0	0.0	0.0	0.0
Latvia	1.3	1.3	1.4	1.3	1.4
Lithuania	2.5	2.5	2.2	2.3	2.3
Luxembourg	1.0	0.9	0.8	0.8	0.8
Hungary	8.5	9.1	9.7	10.4	10.1
Malta	0.0	0.0	0.0	0.3	0.3
Netherlands	40.6	40.1	39.5	43.3	43.0
Austria	7.8	8.3	8.7	9.5	9.1
Poland	17.9	18.2	19.1	20.4	20.8
Portugal	4.1	4.7	5.2	6.3	5.8
Romania	11.6	11.2	11.4	12.3	12.0
Slovenia	0.8	0.8	0.9	0.9	0.9
Slovakia	3.8	4.6	4.7	4.7	4.6
Finland	3.1	2.7	2.5	2.3	2.6
Sweden	0.9	0.8	0.9	1.1	1.1
UK	70.9	72.3	81.5	79.4	80.8

* Note that values provided in this tables are in bcm as reported by Eurostat. These slightly differ from bcm in natural gas equivalent calculated based on the LHV of EU high calorific gas in this study.