Gas Decarbonisation Pathways 2020–2050

Gas for Climate

April 2020

GAS FOR CLIMATE
A path to 2050

Guidehouse

Imprint

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April 2020

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Message from the Gas for Climate consortium

Dear reader,

The Gas for Climate consortium is glad to present to you our new study, which analyses decarbonisation pathways from 2020 to 2050. The pathways target the Optimised Gas 2050 energy system as described in our earlier study, *Gas for Climate. The optimal role for gas in a net-zero emissions energy system*, published in 2019. During the past year, we have had many discussions with EU stakeholders on the 2019 Gas for Climate study, giving rise to one central question: How do we transition from today's energy system to the 2050 net-zero emissions system? This new study answers this question by analysing and mapping out decarbonisation pathways for different sectors and implications for gas infrastructure.

The central decarbonisation pathway of our new study is called the Accelerated Decarbonisation Pathway. It shows how a step-wise approach, seizing investment opportunities in the coming decade, can put Europe on course towards a faster and more cost-effective decarbonisation of its energy system compared to current EU trends. This does require the European Green Deal to accelerate investments by improving business cases and providing a stable framework.

In this time of unprecedented public health challenges and economic pressure, climate change mitigation and economic recovery must go hand in hand. In the aftermath of the current health crisis, the required EU and national stimulus packages should also be seen as a three-fold opportunity for Europe. Beyond creating economic growth, stimulus packages can drive forward the energy transition and create sustainable jobs. Building up European hydrogen and biomethane value chains as described in these pathways has major economic and industrial benefits and creates large numbers of new sustainable jobs in globally relevant sectors.[1]

Our new study offers a pathway towards cost-effective and resilient energy system integration. We support the transition to a fully renewable energy system in which biomethane and green hydrogen play a major role in a smart combination with renewable electricity and Europe's well-developed existing infrastructure. We also recognise that blue hydrogen can accelerate decarbonisation efforts and highlight the ability of biomethane combined with CCS to create negative emissions.

1 The Gas for Climate study *Job creation by scaling up renewable gas in Europe* (Navigant, 2019), showed that scaling up biomethane and hydrogen production in Europe can create 600,000 to 850,000 direct jobs plus over a million indirect jobs. See: https://gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_Job_creation_by_scaling_up_renewable_gas_in_Europe.pdf

EU policy must be strengthened to effectively foster a fully integrated energy system. Gas for Climate would like policymakers to acknowledge that electricity and gas are not in competition with each other but are both needed and can reinforce each other. The Gas for Climate consortium is fully convinced that coupling the sectors electricity, gas and heat – by linking their markets and their respective infrastructures in a better coordinated and integrated way – provides the greatest overall benefits for the European energy system. The consortium therefore endorses the reports recommended cross-sectoral policy measures for inclusion in the European Green Deal:

1. Adapt the EU regulatory framework to make gas infrastructure future proof in an integrated energy system. It will be a key asset for the sustainable and cost-efficient decarbonisation of the European economy.
2. Stimulate the production of biomethane and hydrogen by a binding mandate for 10% gas from renewable sources by 2030.
3. Foster cross-border trade of hydrogen and biomethane, by amongst others a well-functioning Guarantee of Origin system. Clarify market rules for green and blue hydrogen including for hydrogen transport.
4. Incentivise demand for hydrogen and biomethane by strengthening and broadening the EU Emissions Trading System (ETS) combined with targeted and time-bound Contracts for Difference.

The consortium was supported by Guidehouse (formerly known as Navigant Consulting) in the development of this report.

We look forward to discussing these pathways and recommendations with you in the coming weeks and months!

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Executive summary

The EU has embraced the target to make Europe a climate-neutral continent by 2050, and the European Commission proposed an EU Climate Law that would make this a legally binding objective. In the Commission's EU Green Deal communication, it concluded that greenhouse gas emission reduction goals for 2030 need to be increased from 40% to either 50% or 55% to achieve this goal. The European Parliament has indicated a preference for the latter target. The European Green Deal's ambition needs to translate into significant public and private investments in energy efficiency, renewable energy, new low carbon technologies, and grid infrastructure. Such investments are made for a period of 20–60 years, which means that in many cases only one investment cycle remains between now and 2050. Companies, investors, and policy makers need to understand what types of investments are needed, at what scale and by when. For the EU to achieve a 55% greenhouse gas emission reduction by 2030 and climate neutrality by mid-century, renewable molecules, renewable electricity, and a more integrated use of the electricity grids and the gas grids are required. Renewable and low carbon gases and gas infrastructure have an important role to play to cost-effectively achieve a reliable net-zero EU energy system by 2050.

Hydrogen and biomethane can be used for almost all energy end use. In some cases, such as for heavy industry, full decarbonisation is difficult to achieve without the use of gas. In power generation, using hydrogen and biomethane for the dispatchable electricity that complements large shares of wind and solar power avoids an overly expensive climate transition and assures security of supply at all times. Elsewhere, such as in heating buildings, the combined use of gas and electricity reduces societal cost and increases optionality, and therefore the likelihood that Europe can achieve climate neutrality by mid-century. A smart energy system integration means that renewable and low carbon gases are transported, stored, and distributed through gas infrastructure and are used in a smart combination with the electric grid to transport increasing amounts of renewable electricity.

A smart energy system integration increases the likelihood that the EU can meet its climate goals

This new Gas for Climate study develops gas decarbonisation pathways from 2020 to 2050, and identifies what investments and actions are needed across the energy system along the way. The central pathway in this study achieves the 2050 Optimised Gas end state, as analysed in the Gas for Climate 2019 study.

The Gas for Climate study published in 2019 showed that a smart combination of renewable electricity and gas can fully decarbonise the EU energy system at the lowest societal costs.[2] It concluded that it is

2 Navigant, 2019. *Gas for Climate. The optimal role for gas in a net-zero emissions energy system.* Available at: 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

possible to scale-up the deployment of biomethane and hydrogen to 2,900 TWh (net calorific value),[3] which is equivalent to 270 bcm of natural gas. It also showed that renewable electricity should be scaled up sevenfold by 2050 (to almost 7,000 TWh) to enable full decarbonisation. The study concluded that, compared to a Minimal Gas scenario, the Optimised Gas scenario leads to societal cost savings of over €200 billion annually by 2050.[4]

This study develops gas decarbonisation pathways from today towards an optimal climate neutral energy system by 2050

The present study analyses individual decarbonisation pathways for the demand side (buildings, industry, transport, power generation) that are matched with scale-up pathways for biomethane and hydrogen. The specific pathways are blended in three overall pathway scenarios that also include implications for gas infrastructure:

- **Current EU Trends Pathway:** Expected developments during the period from 2020 to 2030 based on full implementation of the existing EU 2030 climate and energy policies. It concludes that current climate and energy policy falls short of what is needed to achieve timely and cost-efficient full decarbonisation; developments would be too slow to enable a scale-up of renewable and low carbon gas in line with the Gas for Climate 2050 Optimised Gas end state.
- **Accelerated Decarbonisation Pathway:** The supply and demand of renewable electricity, hydrogen, and biomethane will accelerate by grasping innovations and investment opportunities. Gas infrastructure will increasingly diversify to facilitate flows of hydrogen and biomethane. This pathway leads to proposals for the European Green Deal, which can be a great accelerator of low carbon investments by improving business cases and by providing a stable framework.
- **Global Climate Action Pathway:** The rest of the world follows Europe's example in reducing greenhouse gas emissions in line with climate science and the Paris Agreement. This optimistic scenario spurs innovation in clean technologies globally and achieves even faster decarbonisation including an accelerated deployment of renewable and low carbon gases and international trade in renewable energy carriers.

EU policy must be strengthened to effectively foster the decarbonisation of the European gas sector. We recommend the EU Green Deal include the following cross-sectoral policy measures:

1. Adapt the EU regulatory framework to make gas infrastructure future proof in an integrated energy system. It will be a key asset for the sustainable and cost-efficient decarbonisation of the European economy.
2. Stimulate the production of biomethane and hydrogen by a binding mandate for 10% gas from renewable sources by 2030.
3. Foster cross-border trade of hydrogen and biomethane, by amongst others a well-functioning Guarantee of Origin system. Clarify market rules for green and blue hydrogen including for hydrogen transport.
4. Incentivise demand for hydrogen and biomethane by strengthening and broadening the EU Emissions Trading System (ETS) combined with targeted and time-bound Contracts for Difference.

Additional sector-specific policy recommendations are detailed in Chapter 4.

2020: Gas infrastructure serves natural gas and renewable and low carbon gases in their infancy

Gas infrastructure is essential to providing energy security as it transports and stores large volumes of natural gas. Biomethane and hydrogen still play

3 Energy supply and demand throughout the report are reported on a net calorific value (NCV) value basis. The NCV, or lower heating value (LHV), is the total heat produced by burning a fuel, minus the heat needed to evaporate the water present in the fuel or produced during its combustion. Definition based on OECD/IEA, 2014. *Energy Statistics Manual*. Available at: https://ec.europa.eu/eurostat/ramon/statmanuals/files/Energy_statistics_manual_2004_EN.pdf. Specifically for natural gas, the NCV is 90% of the gross calorific value (GCV), or higher heating value (HHV).

4 Costs throughout the report are reported as real costs in €2020.

a minor role today. So far, the energy transition has mainly been an electricity transition. While there is increased awareness about the valuable role hydrogen and biomethane will play in the future, the potential of renewable and low carbon gases has yet to be unleashed. A noticeable amount of biogas (around 170 TWh/year) is already being produced; however, this is mostly in the form of locally produced biogas that is used to produce baseload electricity and heat. Green hydrogen production is virtually non-existent today, although an impressive number of pilot projects are ongoing and in development. The first large-scale blue hydrogen projects are under development and can be expected during the next 5 years.

The previous Gas for Climate study identified that biomethane and hydrogen will have a valuable role in several parts of the future energy system, as it can:

- Provide storable and dispatchable renewable electricity alongside wind and solar PV
- Heat buildings that have gas grid connections with hybrid heating solutions
- Provide high temperature heat and feedstock in energy-intensive heavy industry
- Provide an energy-dense fuel to heavy and long-distance road transport and shipping
- Provide the feedstock for synthetic kerosene for aviation

However, blue and green hydrogen and biomethane are not available in large quantities today and must be scaled up. Not enough buildings are being insulated today to decrease their energy demand or to make them suitable for hybrid heating solutions. While hybrid heat pumps consist of well-known components, this combination of a gas-fired boiler and an electric heat pump has not made its way to European buildings yet. Heavy industry has just begun to assess its options for full decarbonisation. Electric passenger cars have started to ramp up, but it is still early days for the decarbonisation of heavy road transport, shipping, and aviation.

Power generation is already decarbonising rapidly, mainly by growing the share of renewable electricity and by natural gas replacing coal. Even in a business as usual scenario, the share of renewable electricity will continue increasing because of rapidly decreasing costs. A rapid increase in wind power and solar PV will increase the need for energy storage. Energy storage can be delivered by batteries for several days, and battery costs decrease rapidly. However, batteries are not suitable for storage that is longer or seasonal. Gas storage can provide longer-term energy storage at low costs.

Current EU climate and energy policies enable a limited scale-up of renewable and low carbon gas

Europe's current energy and climate policies and national energy and climate plans (NECP) are largely based on the EU Clean Energy Package, launched in November 2016. The policies aim to achieve a greenhouse gas emission reduction of 40% by 2030, compared to 1990 levels. The energy efficiency and renewable energy targets were revised upwards in 2018, effectively raising the resulting overall greenhouse gas reduction by 2030 from 40% to 46%. Existing policies continue to drive the effort to green electricity supply. Renewable electricity is expected to reach a share of around 55% in 2030, which is a significant achievement.

EU climate policies that led to a record-speed decarbonisation of electricity production are not designed to decarbonise gas

Yet, the same policies and subsidy schemes that drive a rapid decarbonisation of electricity production were not designed to decarbonise gas. Current EU climate and energy policies do not provide structural drivers for the increase of biomethane supply to the gas grid. During the 2020s, production of green hydrogen will mainly be restricted to pilot and demonstration projects, as almost all renewable electricity will still be needed to satisfy the growing demand for direct electricity. The expected 2030 CO_2 price (around €35/tCO_2 based on the current EU ETS, broadly in line with IEA WEO 2019) is not enough to introduce blue hydrogen as a large-scale replacement of grey hydrogen produced without carbon capture and storage (CCS), which requires a CO_2 price of around €50/tCO_2. Nor will there be sufficient incentives to accelerate the development and scale-up of green hydrogen techniques.

On the energy demand side, current policies provide little long-term certainty and too low a carbon price for heavy industry to invest in deep decarbonisation technologies during major reinvestment moments in the 2020s. In buildings, Europe will not see a significant acceleration of energy renovations. In transport, current policies stimulate the decarbonisation of light road transport, while EVs become cheaper and driving ranges increase. However, it is difficult to see current policies and available technologies leading to deep decarbonisation in shipping and aviation, which both require renewable molecules.

As a result, the Current EU Trends Pathway shows that developments in the 2020s will be too slow to scale-up renewable and low carbon gas in line with the Gas for Climate 2050 Optimised Gas end state.

In this scenario, existing gas infrastructure continues to be used for the import, transport, and storage of natural gas, with some increased grid injection of biomethane and some relatively short, dedicated hydrogen pipelines to transport hydrogen point-to-point, mainly within industrial clusters.

Much more is possible: Accelerated Decarbonisation Pathway

Because current EU climate and energy policies and NECPs fall short of achieving net-zero emissions by 2050, this study analyses two pathways that go beyond current policies and achieve net-zero emissions by 2050. The Accelerated Decarbonisation Pathway is based on the emerging EU Green Deal, which was announced by the European Commission in December 2019. It is our central scenario and explores what is needed to deliver a greenhouse gas reduction of 55% by 2030 compared to 1990 levels, and to get on track for net-zero emissions by 2050. The scenario includes necessary actions by the energy, industry, buildings, and transportation sectors to decarbonise rapidly with the help of renewable and low carbon gases.

In the Accelerated Decarbonisation Pathway, the scale-up of private investments is driven by a more ambitious political and regulatory framework, providing long-term policy certainty. This results in energy renovations for buildings ramping up much faster, and hybrid heating solutions being actively brought to the market. Heavy industry would get long-term policy certainty and an assumed higher EU ETS price of around €55/tCO_2 in 2030, gradually increasing to €150/tCO_2 by mid-century to allow deep decarbonisation in all industrial processes. Accompanied by additional support measures, this would enable strong developments in the coming decade:

- Heavy industry uses natural reinvestment cycles to convert industrial facilities into net-zero emissions industrial sites from the 2020s onwards, based on using hydrogen and biomethane alongside renewable electricity.
- Heavy road transport starts to decarbonise with a rapidly growing role for hydrogen fuel cell trucks, as well as electric trucks, and trucks running on bio-LNG (liquefied biomethane) or bio-CNG.
- Ocean shipping rapidly moves towards the use of LNG (liquefied natural gas) as a fuel, paving the way for bio-LNG and possibly ammonia.
- Aviation starts taking up substantial quantities of biokerosene and synthetic kerosene, based on green hydrogen.
- The share of renewable electricity in power generation increases to 60%-70% by 2030, including 40%-50% from intermittent renewable sources. The remaining 20% comes from dispatchable hydropower plants and bio-based power plants.

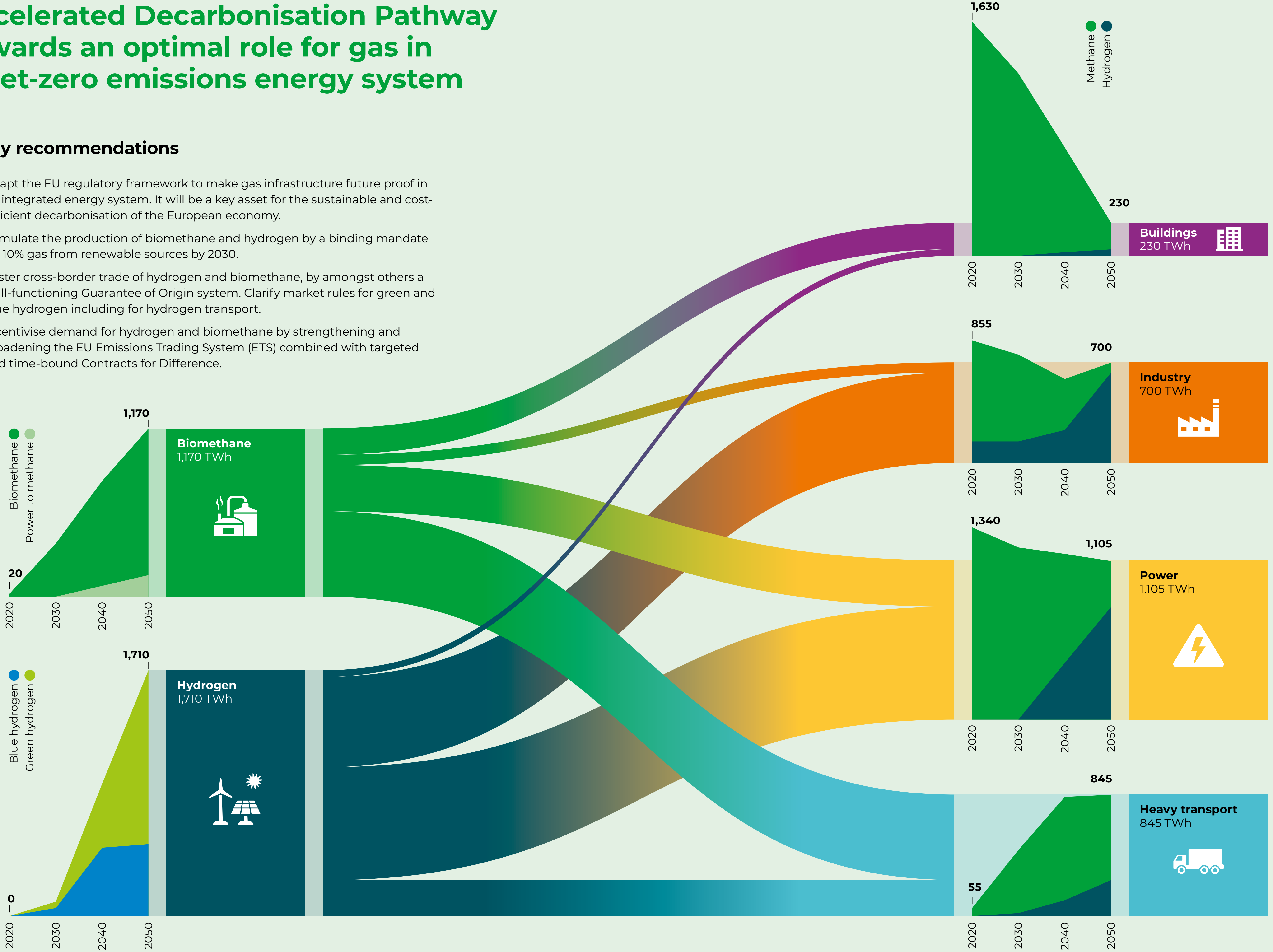
Increasing the share of intermittent renewable electricity after 2030 should be combined with flexible, dispatchable electricity, requiring large-scale production of green hydrogen, which can benefit from reduced electrolyser costs. Large blue hydrogen projects at industrial clusters are enabled by the higher CO_2 price and improved long-term policy security. These projects will start to replace grey hydrogen as industrial feedstock. Green hydrogen is ramped up to take on a major role in the 2030s and to gradually overtake and replace blue hydrogen. Some of the installations that initially produce blue hydrogen can later be fed with part of available biomethane to create much-needed negative emissions (climate positive hydrogen). These installations could be relevant beyond 2050.

The scenario includes a rapid increase in the deployment of sustainable biomethane based on the responsible use of biomass waste and residues plus an increase in the sustainable supply of biomass from sequential cropping and carbon farming, mainly in the southern half of the EU. Large biomethane gasification units emerge at industrial locations and biogas digesters become a common sight in the European countryside. Ultimately, by 2050, biomethane supply will be constrained by the supply of sustainable biomass with low indirect land-use change (ILUC) risks. Green hydrogen is in principle demand constrained by 2050, given that a cheap supply of renewable electricity as feedstock will be abundantly available.

Accelerated Decarbonisation Pathway towards an optimal role for gas in a net-zero emissions energy system

Policy recommendations

1. Adapt the EU regulatory framework to make gas infrastructure future proof in an integrated energy system. It will be a key asset for the sustainable and cost-efficient decarbonisation of the European economy.
2. Stimulate the production of biomethane and hydrogen by a binding mandate for 10% gas from renewable sources by 2030.
3. Foster cross-border trade of hydrogen and biomethane, by amongst others a well-functioning Guarantee of Origin system. Clarify market rules for green and blue hydrogen including for hydrogen transport.
4. Incentivise demand for hydrogen and biomethane by strengthening and broadening the EU Emissions Trading System (ETS) combined with targeted and time-bound Contracts for Difference.



Source: Guidehouse

Gas infrastructure ensures the reliability and flexibility of the energy system.

In 2050, gas transmission and distribution networks will continue to have a valuable role transporting biomethane and hydrogen. In the Accelerated Decarbonisation Pathway, gas infrastructure still transports a small remaining volume of natural gas used for blue hydrogen. Total volumes of natural gas, biomethane, and hydrogen transported in networks will be lower in 2050 than in 2019, but transport capacity needed for peak demand will likely show a smaller decrease. EU natural gas infrastructure is already well-developed today. It has enough available capacity to handle future renewable and low carbon gas volumes in a decarbonised energy world (apart from regional capacity issues due to a switch from coal to gas or development of additional gas import lines). Due to gas demand reduction, capacity will become available that can be used to convert pipeline segments to hydrogen transport. Blending natural gas with a limited amount of injected hydrogen can be an effective temporary solution to boost hydrogen production and facilitate CO_2 emission reductions during the 2020s. However, the volumes of hydrogen needed to reach a net-zero emission energy system in 2050 will require a separate regional and national pure hydrogen infrastructure around 2030, as well as trans-EU hydrogen flows around 2040. Such infrastructure can be largely based on existing gas infrastructure, which can be retrofitted cost-effectively (as described in the Gas for Climate 2019 study). While part of existing gas transmission infrastructure will be retrofitted to carry hydrogen, part of it will remain in use to transport decreasing volumes of biomethane, some power to methane, and remaining volumes of natural gas for blue hydrogen. Gas distribution infrastructure will be used to collect biomethane from farms and other decentral sources and deliver it to buildings.

Separate regional, national and eventually European hydrogen infrastructures will be required from 2030 onwards when hydrogen volumes increase

Regulatory and policy developments are needed to support the evolution of gas infrastructure to the future supply and demand of low carbon and decarbonised gases. Current policies are not developed to cope with declining gas volumes and with repurposing assets from natural gas to hydrogen.

The figure below provides a high level overview of the Accelerated Decarbonisation pathway between 2020 and 2050.

Major upside when other parts of the world join in the development: the Global Climate Action Pathway

The Accelerated Decarbonisation Pathway assumes that the decarbonisation of the EU energy system is largely driven by governments and companies within the EU. It also assumes that renewable and low carbon gases largely come from domestic EU sources. The pathway does not depend on what happens in other parts of the world.

However, 195 countries from all over the world joined the Paris Agreement, and they all face the challenge of rapid decarbonisation in coming decades. The challenges vary by region, but there are similarities regarding the energy system. If countries around the world start to work towards meeting the Paris Agreement goals, high shares of renewable energy will play a major role globally, and so will electrification. Many places increasingly recognise the role that renewable and low carbon gases can play. Examples include interest in biogas and biomethane in China, the development of hydrogen initiatives worldwide, and the debate on the future role of gas emerging in North America.

An Accelerated Decarbonication Pathway towards a net-zero emissions energy system by 2050

1

Preparing for transition

Strategic, technical and policy planning to enable renewable and low carbon gases to play a significant role along side renewable electricity in the transition to net-zero

Long-term infrastructure strategy for conversion of existing pipelines to hydrogen

Changes to legislation and regulation in favor of conversion and H_2 readiness

2

Facilitating connections

Scale-up in **biomethane** plants that are close to the gas grid

Start first **hydrogen** projects

Energy efficiency improvements in all sectors to enable electrification and the uptake of renewable and low-carbon gases

3

Kick-starting supply

First **hydrogen** projects integrated with carbon capture, utilisation, and storage (CCUS) and anchored by baseload consumers, likely from Industry

Develop regional hydrogen backbones

Continuing scale-up of **biomethane** supply

4

Broadening demand

Hydrogen use extends to commercial and residential consumers around first hydrogen projects

Blending (up to 20%) increases initial demand fast, paving the way for hydrogen clusters (100%)

Consumers in other regions continue to receive natural gas with rising blends of **biomethane**

5

Creating dedicated methane and hydrogen networks

Greater volumes and diversification of renewable and low carbon gas supply as more production methods mature technically and economically

Hydrogen infrastructure develops from regional to transmission via an EU-wide backbone

6

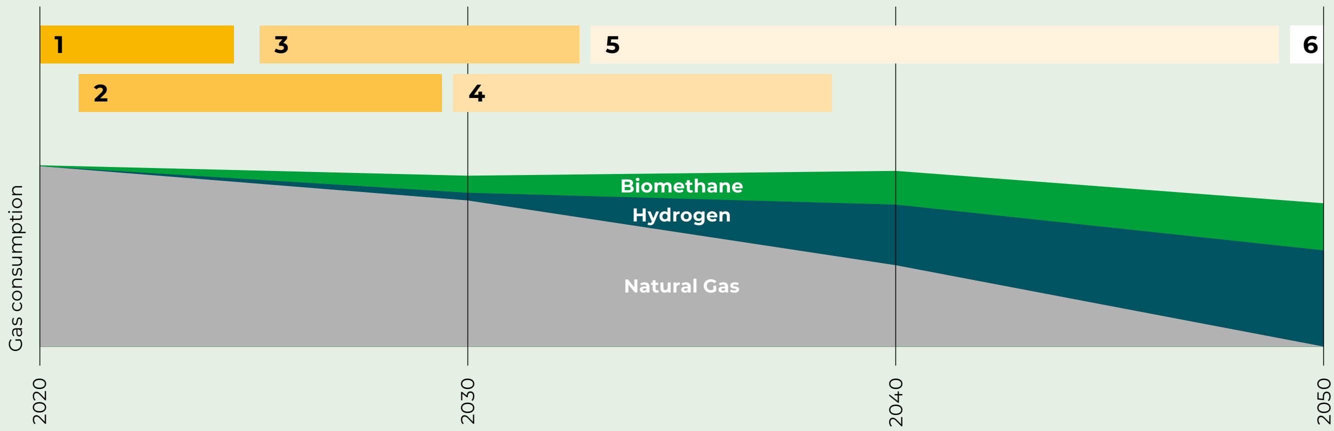
100% renewable and low Ccarbon gases

Renewable and low carbon gases fully integrated across the EU energy system

All gas end-users are supplied with **hydrogen** and/ or **biomethane**, principal type varying by region

Natural gas is no longer used, unless abated with CCUS for blue hydrogen production

Net-zero energy system achieved in 2050



Source: Guidehouse

The Global Climate Action Pathway assumes that, if other continents increase climate mitigation actions, the speed, scale, and cost of renewable and low carbon gas developments will benefit the EU's energy transition. Overall, technology costs will decrease faster on the demand side (e.g. hybrid heating solutions and hydrogen trucks) and the supply side (e.g. in biomethane from gasification and imported green and blue hydrogen). Opportunities for importing cheap renewable energy will also arise, such as methanol and synthetic kerosene produced from hydrogen outside Europe. As a result, the energy transition will go faster and at lower societal costs. This provides a major upside for the societal costs of the energy transition compared to the Accelerated Decarbonisation Pathway.

Content

Abbreviations

A

ASU	Air separation unit
ATR	Autothermal reforming

B

BAU	Business as usual
bcm	Billion cubic meters*
BECCS	Bio-energy with carbon capture and storage
BEV	Battery electric vehicle

C

CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CfD	Contracts for Difference
CH_4	Methane
CHP	Combined heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide

D

DRI	Direct reduction of iron ore
DSO	Distribution system operator

E

EED	Energy Efficiency Directive
EPBD	Energy Performance for Buildings Directive
EU ETS	EU Emission Trading Scheme
EUA	European Emission Allowance
EV	Electric vehicle

F

FCV	Fuel cell vehicle

G

GCV**	Gross calorific value
GW	Gigawatt

H

H_2	Hydrogen
HHV**	Higher heating value
HVC	High value chemical

I

ICAO	International Civil Aviation Organisation
ICE	Internal combustion engine
IEA	International Energy Agency
ILUC	Indirect land-use change
IMO	International Maritime Organisation

K
km Kilometre
kWh Kilowatt-hour

L
LCOE Levelised cost of energy
LHV** Lower heating value
LNG Liquefied natural gas
LTRS Long-Term Renovation Strategies

M
MaaS Mobility as a service
MTO Methanol to olefins
MWh Megawatt-hour

N
NCV** Net calorific value
NECP National energy and climate plan
NGO Nongovernmental organisation
NH_3 Ammonia
NOAK N^{th} of a kind

O
OCGT Open cycle gas turbine
OPEX Operational expenditure

P
PV Photovoltaic

R
RED Renewable Energy Directive

S
SMR Steam methane reforming
SNG Synthetic natural gas

T
TCO Total cost of ownership
TSO Transmission system operators
TWh Terawatt hour
TYNDP Ten Year Network Development Plans

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* When energy supply and demand is provided in bcm natural gas equivalent, energy in TWh is converted to bcm based on a lower heating value (LHV) for natural gas of 38.2 MJ/m^3 (EU high calorific natural gas). 1 bcm natural gas equivalent equals 10.61 TWh.

** Energy supply and demand throughout the report are reported on a net calorific value (NCV) value basis. The NCV, or LHV, is the total heat produced by burning a fuel, minus the heat needed to evaporate the water present in the fuel or produced during its combustion.[5] Specifically for natural gas, the NCV is 90% of the gross calorific value (GCV) or higher heating value (HHV).

5 Definition based on OECD/IEA, 2014. *Energy Statistics Manual*. Available at: https://ec.europa.eu/eurostat/ramon/statmanuals/files/Energy_statistics_manual_2004_EN.pdf.

1. Introduction

The European Union aims to fully decarbonise the EU economy, which requires a complete overhaul of the energy system and its infrastructure by 2050. The European Commission announced the European Green Deal in December 2019, which includes a wide variety of plans to step up climate mitigation policies. Raising the ambitions of EU climate policy will require significant investment in energy efficiency, renewable energy, new low carbon technologies, and grid infrastructure. It will also necessitate the close integration of the electricity and gas sectors and their respective infrastructures. A decarbonised Europe will be based on an interplay between the production of renewable electricity and the conversion of green electrons into green molecules to transport, store, and supply all sectors with renewable energy at the lowest possible costs. Because the necessary investments are made for a period of 20–60 years, it is important to understand what types of investments are needed at what scale and by when. This study seeks to shed light on the future design of a fully integrated energy system and formulates recommendations for the emerging EU Green Deal. These recommendations could help accelerate business cases and promote a stable framework to unlock the large investments required to fully decarbonise the EU economy at the lowest societal costs. This study explores EU decarbonisation pathways for gas and gas infrastructure between 2020 and 2050. Large investments and difficult decisions are required to fully decarbonise the energy system at the lowest societal costs, yet there is ample opportunity to create new employment and to make Europe the global leader in low carbon technologies.

The present study is an update to the 2019 study for the Gas for Climate consortium done by Navigant, now called Guidehouse.[6] That study, called, *Gas for Climate. The optimal role for gas in a net-zero emissions energy system*, explored the role and value for renewable and low carbon gases in a net-zero EU energy system in 2050. It analysed the potential of biomethane and hydrogen produced in the EU, and the energy system cost benefits of using them through existing gas infrastructure to achieve a net-zero emissions EU energy system. The study found that there is a large opportunity to scale-up renewable gas production in the EU and concluded that full decarbonisation with a role for renewable gas offers significant societal cost benefits. The energy system costs of an Optimised Gas scenario were compared to those of a Minimal Gas scenario. The Optimal Gas scenario offered over €200 billion in cost savings per year by 2050.

This study explores decarbonisation pathways for gas and gas infrastructure between 2020 and 2050

6 On October 11, 2019, Guidehouse LLP completed its previously announced acquisition of Navigant Consulting Inc. The Guidehouse and Navigant businesses are currently being integrated. In furtherance of that effort, Navigant Consulting Inc. has recently been renamed as Guidehouse Inc.

The current study analyses the road towards 2050. It explores EU energy system decarbonisation pathway scenarios between 2020 and 2050, focussing on the role of gas and gas infrastructure. Three pathway scenarios are described, including a central Accelerated Decarbonisation Pathway. This pathway assumes that the recently announced EU Green Deal can accelerate the decarbonisation of the EU gas demand, enabling Europe to decarbonise at the lowest possible costs as described in the Gas for Climate 2019 Optimised Gas scenario. In addition, two alternative pathways are being analysed as well as several sensitivities to the central Accelerated Decarbonisation Pathway.

1.1 Gas for Climate

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

Gas for Climate consists of ten leading European gas TSOs and two biomethane associations

Gas for Climate: The optimal role for gas in a net-zero emissions energy system

In March 2019, Gas for Climate published a study by Navigant that analyses how Europe can achieve climate neutrality by 2050 at the lowest societal costs. The study compares the following two scenarios:

- **Optimised Gas scenario:** A combination of renewable electricity and gas are used to fully decarbonise the EU industry, buildings, and transport sectors.
- **Minimal Gas scenario:** Full decarbonisation with a minimal role for gas and existing gas infrastructure.

The study showed that it is possible in the Optimised Gas scenario to scale-up biomethane and hydrogen to about 2,900 TWh, or about 270 bcm of natural gas energy equivalent, consisting of about 1,170 TWh of biomethane, of which about two-thirds comes from biogas produced through anaerobic digestion and one-third comes from biomass gasification. In addition, about 1,710 TWh of hydrogen is produced. This hydrogen is largely green hydrogen, but some blue hydrogen may still be part of the mix. The quantity of biomethane is limited to the sustainable availability of biomass while, by 2050, the quantity of hydrogen would be limited by the available demand for hydrogen. Renewable electricity should be scaled up tenfold by 2050 to allow full decarbonisation. The study concludes that, compared to the Minimal Gas scenario, the Optimised Gas scenario leads to a societal cost saving of over €200 billion annually by 2050.

Annual cost savings in the Optimised Gas scenario as compared to the Minimal Gas scenario arise from lower costs for insulation and heating technologies in buildings (€61 billion), using hydrogen transported through gas infrastructure to decarbonise high temperature industrial heat (€70 billion), lower energy costs in transport (€14 billion), deployment of gas-fired dispatchable power as compared to more expensive solid biomass-fired dispatchable power (€54 billion) and efficient use of energy infrastructure (€19 billion).

Sector	Cost savings (billion € per year)
Buildings	61
Industry	70
Transport	14
Power	54
Infrastructure	19
Total	**217**

Looking at EU gas demand in 2050, about 230 TWh (mostly biomethane) goes to the buildings sector where it is used in hybrid heat pumps in older buildings that already have a gas connection today. Some 850 TWh of renewable gas is used in heavy transport: hydrogen and bio-LNG in long distance truck transport and bio-LNG in international shipping. Nearly 700 TWh of gas (mostly hydrogen) is used to decarbonise heavy industry. About 1,100 TWh of gas is used to produce dispatchable electricity, allowing a large scale-up of wind power and solar PV. The following figure represents the Optimised Gas scenario.

Source: Navigant 2019

Renewable gas would be cost-efficiently transported, stored, and distributed through existing gas infrastructure. A limited investment is required to enable part of the transmission grid to transport hydrogen and possibly the construction of a limited number of new dedicated hydrogen pipelines. The gas distribution grids would mainly be used to distribute biomethane to households.

1.2 Study aim and scope

The 2019 Gas for Climate study informed the European debate on how the EU energy system can be fully decarbonised in a cost-effective way. There is increasing consensus across Europe regarding the need to fully decarbonise by 2050 and the notion that this will require a complete overhaul of the current fossil fuel-dominated energy system and a large scale-up of renewable electricity. Moreover, an energy system based on intermittent wind and solar requires substantial storage and transport capacity to handle fluctuations in supply and demand.

Coupling the sectors electricity, gas, and heat—by linking their markets and their respective infrastructure in a better coordinated and integrated way—provides the greatest overall benefits for the European energy system. A fully integrated system creates additional flexibility, in terms of storage and transport capacity, and thus makes the best possible use of the advantages of Europe's well-developed existing infrastructure. This coupled energy system is based on renewable electricity and combined with large quantities of renewable gas, ensuring a cost-efficient decarbonisation of industry, heavy transport, and the buildings sector.

The 2019 Gas for Climate study focused on the optimal decarbonised energy system in 2050. The 2020 study describes how to get there. The 2020 study's pathways focus on the increased supply and demand of renewable and low carbon gas and describe the development of gas infrastructures and the continued increase in renewable electricity. To ensure specific sector needs are considered, Gas for Climate developed pathways for seven topics: biomethane (anaerobic digestion and gasification), hydrogen (blue and green hydrogen), buildings, industry, transport, power, and gas infrastructure (Figure 1).

This study benefits from the thorough reviews of Gas for Climate member organisations. Industry and NGO stakeholders also provided valuable feedback and input on the pathways and their underlying assumptions.

This study describes three pathways:

1. Current EU Trends Pathway

The Current EU Trends Pathway describes how a renewable and low carbon gas pathway develops without the EU Green Deal measures. To determine if reaching the 2050 end state is realistic, the pathway assumes similar efforts in the period 2030–2050 as in the period 2020–2030.

The Current EU Trends Pathway includes all EU policy through 2030, including EU policies that still need to be transposed into national policies; for example, as part of the national energy and climate plans (NECPs). It is not a business as usual scenario since not all EU policies and targets are transposed into national policies; with current developments, the EU targets might not be reached.

2. Accelerated Decarbonisation Pathway

The Accelerated Decarbonisation Pathway shows the accelerated deployment of renewable and low carbon gas as a result of current EU policies and additional policies that could be included in the emerging EU Green Deal, which will be detailed in legislation and a number of strategies, e.g. on EU industry and a circular economy. The pathway is in line with the Paris Agreement's ambition to limit global temperature increase to well below 2°C. As such, the scenario results in 55% emission reductions by 2030 compared to 1990 levels, as included as an ambition for the EU Green Deal.

The Accelerated Decarbonisation Pathway showcases how we can reach an affordable and reliable EU energy system

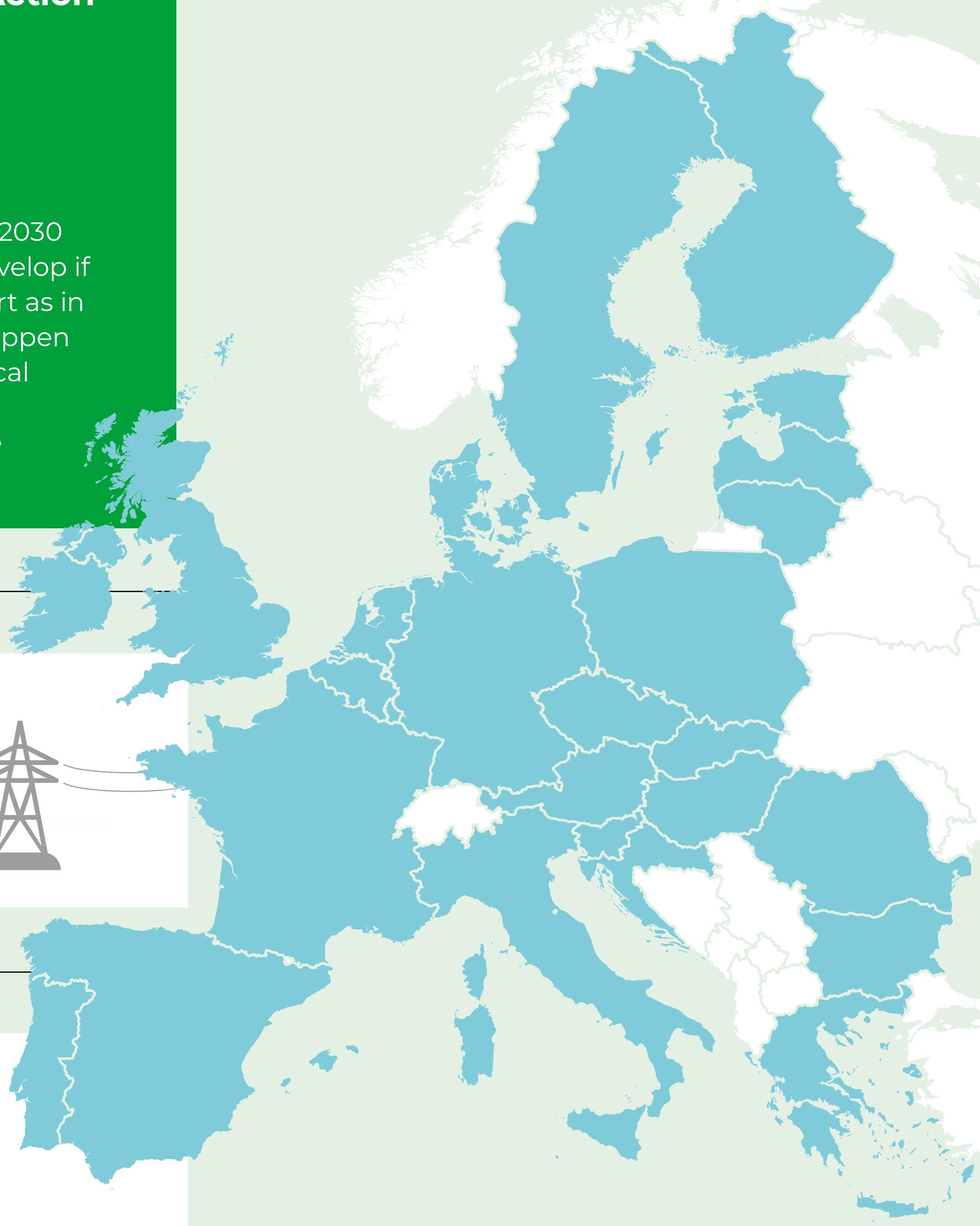
Figure 1. Scope of this study

Three pathway scenarios for 2020 to 2050

Aim

Analyse gas decarbonisation pathways towards cost-effective climate neutrality by 2050

Geography



Pathway scenarios

Current EU Trends Pathway

How can the renewable and low carbon gas pathway develop between today and 2030 in the context of current EU 2030 climate, energy and agricultural policies?

Accelerated Decarbonisation Pathway

How does a plausible 2030 and 2050 pathway develop within the context of accelerated decarbonization efforts enabled by the **EU Green Deal**?

Global Climate Action Pathway

How does a plausible 2030 and 2050 pathway develop if **globally** a similar effort as in the Green Deal will happen leading to technological and commercial **breakthroughs** in the eight sub-pathways?

Energy Supply

Variable renewable electricity

Biomethane

Hydrogen

Infrastructure

Energy demand

Buildings

Transport

Industry

Power

Source: Guidehouse

Until 2030, policy-driven developments in the Accelerated Decarbonisation Pathway will get the European Union on track towards the Gas for Climate 2050 Optimised Gas end state. The Accelerated Decarbonisation Pathway describes developments already proposed under the EU Green Deal in addition to the Current EU Trends Pathway, as well as what additions are required. The Accelerated Decarbonisation Pathway will result in policy recommendations for the EU Green Deal.

3. Global Climate Action Pathway

The Global Climate Action Pathway showcases what happens if countries around the world adopt similar climate change mitigation and renewable energy ambitions as the EU. Just like the Accelerated Decarbonisation Pathway, the Global Climate Action Pathway describes a pathway in line with the Paris Agreement's goals.

Global climate policy leads to accelerated technological development. As such, the developments in the Global Climate Action Pathway are technology driven. Compared to the Accelerated Decarbonisation Pathway, the Global Climate Action Pathway showcases these technologies have the potential to decarbonise the energy system at a higher speed, with lower cost, and with higher renewable and low carbon gas volumes. It may even show potential on top of the Gas for Climate 2050 Optimised Gas end state.

How the Pathways are described in this study

Out of the three pathways, the Accelerated Decarbonisation Pathway is central and features the most prominently in the main study report. The Current EU Trends Pathway is described briefly in Chapter 3 and more extensively in the appendices. Global Climate Action is summarised in Chapter 5 and described in more detail in the appendices.

How the analysis is done

The Gas for Climate 2019 study analysed the 2050 Optimised Gas end state, which resulted from a least-cost optimisation modelling analysis. The pathways described in this study are not modelled as optimised or least-cost scenarios. Instead, the pathways result from logical analysis combined with calculated 2030 energy and technology costs to ensure that the Accelerated Decarbonisation Pathway meets the EU's 55% greenhouse gas reduction target by 2030.

1.3 Reading guide

The study consists of two parts. The first (Chapter 2–5) focusses on the overall study results, with a special focus on the Accelerated Decarbonisation Pathway. The second (appendices) provides specific findings for the seven topics (biomethane, hydrogen, buildings, industry, transport, power and gas infrastructure) and describes all three pathways in detail. Chapter 2 starts with the Accelerated Decarbonisation Pathway, which is our central scenario leading in 2030 to the 55% reduction ambition of the EU Green Deal and to the Gas for Climate Optimised Gas end state in 2050. We first describe accelerated biomethane and hydrogen supply pathways, followed by energy demand decarbonisation pathways, and finally detail the implications for gas infrastructure over time of increased supply and demand of hydrogen and biomethane.

To enable the developments described in Chapter 2, several EU policies are needed. This study first analyses the effect of the current EU energy and climate policies in Chapter 3. We identify that current climate and energy policies are insufficient to drive the required scale-up of hydrogen and biomethane. This subsequently leads to a series of policy recommendations described in Chapter 4. Finally, Chapter 5 summarises the Global Climate Action Pathway and includes a sensitivity analysis on the effect if developments for the different sectors are moving at a different speed or in a different direction, including a description of what could happen if the rest of the world accelerates decarbonisation efforts. The appendices cover the pathway details and contains seven chapters. They can also be read as standalone sections. The descriptions of the Accelerated Decarbonisation Pathway as included in the main study report are duplicated in the appendices to ensure that the appendices contain the full descriptions of all pathways organised by topic.

2.
An Accelerated Decarbonisation Pathway to speed up the energy transition

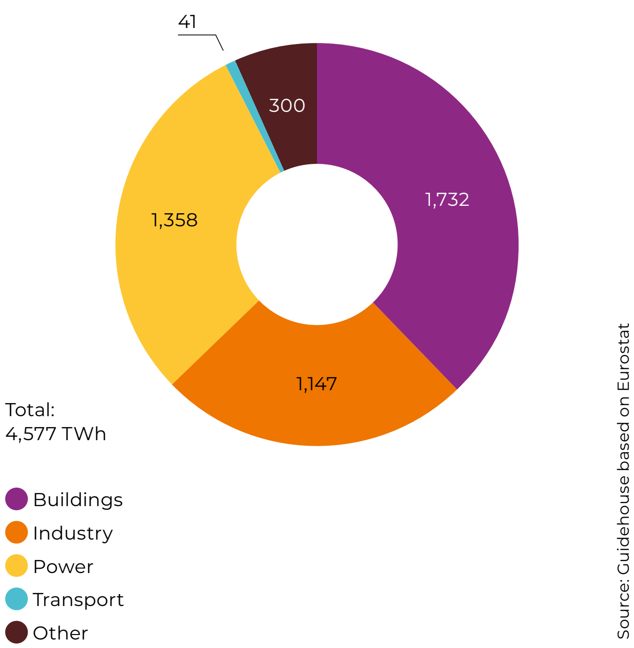
Key takeaways

- Renewable and low carbon gases are still in their infancy. There is significant biogas production today, but it largely has not been upgraded to biomethane. The first green and blue hydrogen investments have been announced.
- The future European energy system will require renewable electricity and the scale-up of renewable and decarbonised gases. The EU Green Deal and its envisaged gas market reform can accelerate an effective decarbonisation of the European gas sector and help facilitate the transformation of Europe's gas infrastructure in the 2020s and to create a more integrated European energy system.
- With the right incentives in place, the energy sector will be able to massively scale-up the production of biomethane and green and blue hydrogen, initially to 10% of total gas demand by 2030 and to 100% renewable and low carbon gas by 2050.
- Gradually, hydrogen production will become renewable based on green hydrogen from renewable electricity. Biomethane used in blue hydrogen installations can create negative emissions also after 2050, which are necessary to compensate for remaining emissions.
- Gas infrastructure can transport, store, and distribute biomethane and hydrogen in a cost-effective way. Around 2030 dedicated hydrogen networks will emerge, gradually leading to separate hydrogen and methane infrastructures.

In the future integrated energy system, electricity and gas fulfil complementary roles. Wind and solar power are the major primary sources of renewable energy. The advantage of transporting electricity directly to sectors where electrification is technically and economically feasible avoids energy conversion losses. Renewable and decarbonised gases will accommodate decarbonisation in sectors that are hard to electrify and can easily be transported in the existing infrastructure. Hence, their role will significantly increase compared to today.

Current EU natural gas demand is 4,577 TWh, mainly used in buildings, industry, and power generation (Figure 2).[7] The full decarbonisation of the EU energy system will change the demand for gas. Natural gas consumption will decrease significantly and, by 2050, can only be used when combined with carbon capture and storage (CCS). Biomethane, green and blue hydrogen will play a valuable role in the full decarbonisation of buildings, transport, industry, and power generation. Overall gas consumption will be lower than today by 2050, but its societal value will remain large.

Figure 2. Current EU natural gas demand (TWh)[7]



Today gas infrastructure plays an important role in transporting and storing large volumes of energy, mainly natural gas while transported volumes of biomethane and hydrogen are currently small. Although around 170 TWh of biogas is already being produced annually, most of this does not reach gas grids and is used locally to produce baseload electricity and heat. Green hydrogen production is virtually non-existent today, although an impressive number of pilot projects are ongoing and in development. The first large-scale blue hydrogen projects are under development and can be expected during the next 5 years.

Current situation: Gas infrastructure serves mainly natural gas; renewable and low carbon gases are still in their infancy

The previous Gas for Climate study identified a valuable role for biomethane and hydrogen in several parts of the energy system. However, blue and green hydrogen and biomethane are not available in large quantities today and need to be scaled up. Also, not enough of today's buildings are being insulated to bring down their energy demand or to make them suitable for hybrid heating solutions. While hybrid heat pumps consist of well-known components, this combination of a gas-fired boiler and an electric heat pump has not made its way yet to European buildings. Heavy industry has only just begun to assess the options for full decarbonisation. Electric passenger cars have started to ramp up, but it is still early days for decarbonisation of heavy road transport, shipping, and aviation.

Power generation is already decarbonising rapidly, mainly by growing the share of renewable electricity, and by natural gas due to a phaseout of coal and the reduced use of nuclear power. Even in a business as usual scenario, the share of renewable electricity is set to continue increasing because

7 Inland consumption in 2018 in net calorific values based on Eurostat, *Supply, transformation and consumption of gas [nrg_cb_gas]*.

of rapidly decreasing costs. A rapid increase in wind power and solar PV will amplify the need for energy storage. Energy storage can be delivered by batteries for several days. While battery costs decrease rapidly, they are not suitable for longer, seasonal storage. Gas storage can provide longer-term energy storage at low costs.

Europe's energy and climate policies and NECPs today are largely based on the EU Clean Energy Package launched in November 2016 and aim to achieve a greenhouse gas emission reduction of 40% by 2030, compared to 1990 levels. The energy efficiency and renewable energy targets were revised upwards in 2018, effectively already raising the resulting overall greenhouse gas reduction by 2030 from 40% to 46%.[8]

Chapter 3 includes analysis demonstrating that current EU climate and energy policies and NECPs fall short of achieving net-zero emissions by 2050. Therefore, this study developed the Accelerated Decarbonisation Pathway. This pathway is based on the emerging EU Green Deal, as announced in December 2019 by the incoming European Commission. The scenario explores what is needed on top of the proposed EU Green Deal measures to deliver 55% greenhouse gas reduction by 2030 compared to 1990 levels. The scenario analyses what (private) actions are needed in the energy, industry, buildings, and transportation sectors to more rapidly scale-up the deployment of renewable and low carbon gases. Following from this scenario, several policy recommendations emerge that can help the private sector scale-up the European gas transition, which are described in Chapter 4.

Much more is possible by 2030 as part of an EU Green Deal under the Accelerated Decarbonisation Pathway

In the Accelerated Decarbonisation Pathway, energy renovations for buildings ramp up much faster, and hybrid heating solutions are brought to the market and actively propagated. Heavy industry is assumed to get long-term policy certainty and an assumed higher EU ETS price of around €55/tCO_2 in 2030, which gradually increases via €100/tCO_2 by 2040 to €150/tCO_2 by mid-century, to allow deep decarbonisation in all industrial processes. Accompanied by additional support measures, this would enable the following:

- Heavy industry uses natural reinvestment cycles to convert industrial facilities into net-zero emissions industrial sites from the 2020s onwards, based on using hydrogen and biomethane alongside renewable electricity.
- Heavy road transport is decarbonised with a rapidly growing role for hydrogen fuel cell trucks as well as electric trucks and trucks running on bio-LNG.
- Ocean shipping rapidly moves towards the use of liquefied natural gas (LNG) as a fuel, paving the way for bio-LNG and possibly ammonia.
- Aviation starts taking up substantial quantities of biokerosene and synthetic kerosene, based on green hydrogen.
- The share of renewable electricity in power generation increases to 60%-70% by 2030: 40%-50% of all electricity comes from intermittent renewable sources, and 20% from dispatchable hydropower plants and bio-based power plants.

Increasing the share of intermittent renewable electricity after 2030 also increases the need for dispatchable electricity and will push large-scale production of green hydrogen. Combined with reduced electrolyser costs and the emergence of large CCS projects, this will accelerate the scale-up of hydrogen. Large blue hydrogen projects at industrial clusters are enabled by the higher CO_2 price and the improved long-term policy security and will initially replace grey hydrogen as industrial

8 Ecofys, 2018. The 35% renewable energy and 35% energy efficiency targets voted for by the European Parliament enable greenhouse gas emission reductions of 50% in 2030. Available at: https://guidehouse.com/-/media/www/site/downloads/energy/2018/ecofysanavigantcompanya-stepclosertoparisupdatejune.pdf

feedstock and will bridge the shortage of green hydrogen during the 2020s and early 2030s. Green hydrogen is ramped up to take on a major role in the 2030s and to gradually overtake and replace blue hydrogen. Some of the installations that initially produce blue hydrogen can later be fed with part of available biomethane to create much-needed negative emissions. These installations could be relevant even beyond 2050.

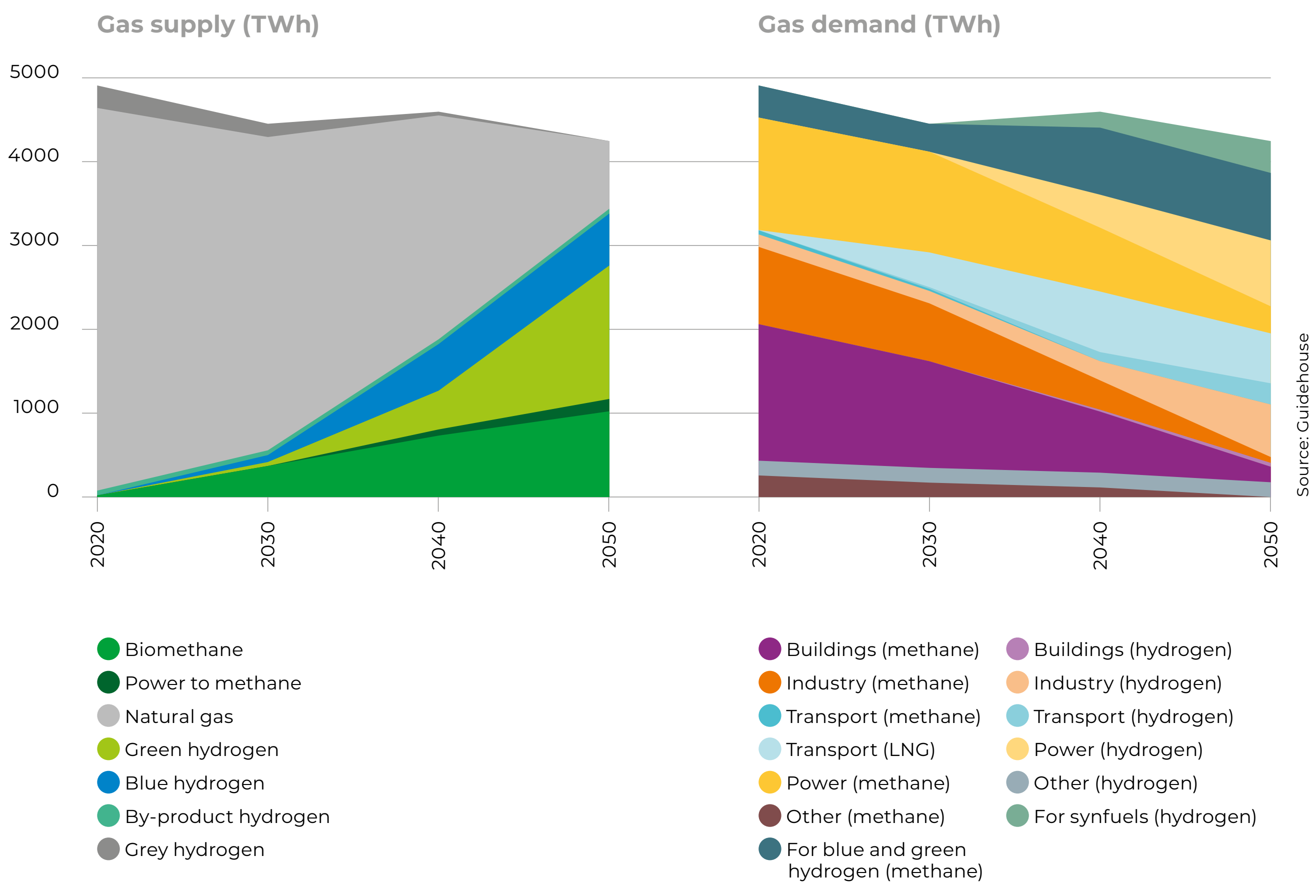
Figure 3 depicts the overall gas supply and demand pathway in the Accelerated Decarbonisation Pathway. Between 2020 and 2030 total gas demand declines as result of energy efficiency efforts and electrification. Meanwhile the share of renewable gases increases to around 10%. While energy efficiency efforts and electrification continue after 2030, gas supply increases slightly for blue hydrogen and synfuel production. Between 2040 and 2050 gas demand declines again. By 2050, all gas supply is renewable or low-carbon gas.

The Accelerated Decarbonisation Pathway is broken into specific gas supply and demand pathways. The rest of this chapter discusses each of these supply and demand pathways.

2.1 Supply of renewable and low carbon gases

The Accelerated Decarbonisation Pathway assumes a rapid increased deployment of sustainable biomethane, green and blue hydrogen, and some power to methane via the existing well-developed European energy infrastructure. A large scale-up potential exists for all these energy carriers.

Figure 3. Gas supply and demand in the Accelerated Decarbonisation Pathway



Ultimately, biomethane potentials are supply constrained, depending on the available supply of sustainable biomass. Ultimately, hydrogen will be demand constrained, depending on how much hydrogen will be required in the net-zero emissions energy system.

2.1.1 Biomethane deployment pathway

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 MWe per plant.[9] 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/m³ to €0.90/m³) 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.[10] 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.[11] 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/m³).[12, 13] 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.

A large sustainable biomethane scale-up potential exists. The Gas for Climate 2019 study included a bottom-up biomass and biomethane potential analysis, plus analysed power to methane production. The study concluded that a quantity of 1,170 TWh can be produced by 2050, consisting of 1,020 TWh of biomethane and 150 TWh power to methane. This requires 30,000 large biogas producers, feeding into even larger biomethane upgrading plants, plus 228 large (200 MW) biomass gasification plants. 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 can be used as feedstock to produce hydrogen and create negative emissions. This hydrogen could be called 'climate positive hydrogen'

9 EBA Annual Report 2019. https://www.europeanbiogas.eu/wp-content/uploads/2020/01/EBA-AR-2019-digital-version.pdf
10 Global Syngas Technologies Council, *The Gasification Industry*, https://www.globalsyngas.org/resources/the-gasification-industry.
11 Bioenergy International, *Göteborg Energi winds down GoBiGas 1 project in advance*, 2018, https://bioenergyinternational.com/research-development/goteborg-energi-winds-gobi-gas-1-project-advance.
12 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
13 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%.

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.[14] 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. An assessment of the feasibility of increasing renewable methane production by methanation of CO_2 captured in biogas upgrading showed that this technology could increase the renewable methane potential; however, costs will remain higher than biomethane or hydrogen costs.

The Accelerated Decarbonisation Pathway envisions a higher ambition level in climate and energy policy and a greater overall societal momentum to combat climate change. In this context, biomethane from anaerobic digestion, a mature form of renewable energy, can be scaled up much more rapidly. Investments in large biomass-to-biomethane gasification plants will also increase more rapidly. This could lead to a situation in which the Accelerated Decarbonisation Pathway could generate 370 TWh or 35 bcm of biomethane per year by 2030 through:

With additional EU climate and energy policies, biomethane supply could reach 370 TWh by 2030

- 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 m³/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 m³/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.[15]
- Constructing 21 large 200 MW gasification plants that jointly produce 3 bcm of biomethane.

14 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

15 Biogasdoneright is an innovative concept of sustainable farming and biogas production developed in Italy. 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.

Digester for biogas production

↑
Biogas production on the farm Principi di Porcia e Brugnera located in Azzano Decimo, Italy (www.porcia.com), member of the Consorzio Italiano Biogas.

→
Fertilisation of the field during winter crop cultivation, with digestate recovered at the farm's biogas plant.

Benas biogas demonstration plant in North Germany, member of EBA, with a capacity of 174 kt/y, distributed over 4 digesters and 2 storage tanks.
↓

All of this will be possible only if:

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

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 through technological improvements and through improved bacterial processes.

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. There is also 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 clarifying who is responsible for managing (cross-border) gas quality.

Increased deployment of Biogasdoneright

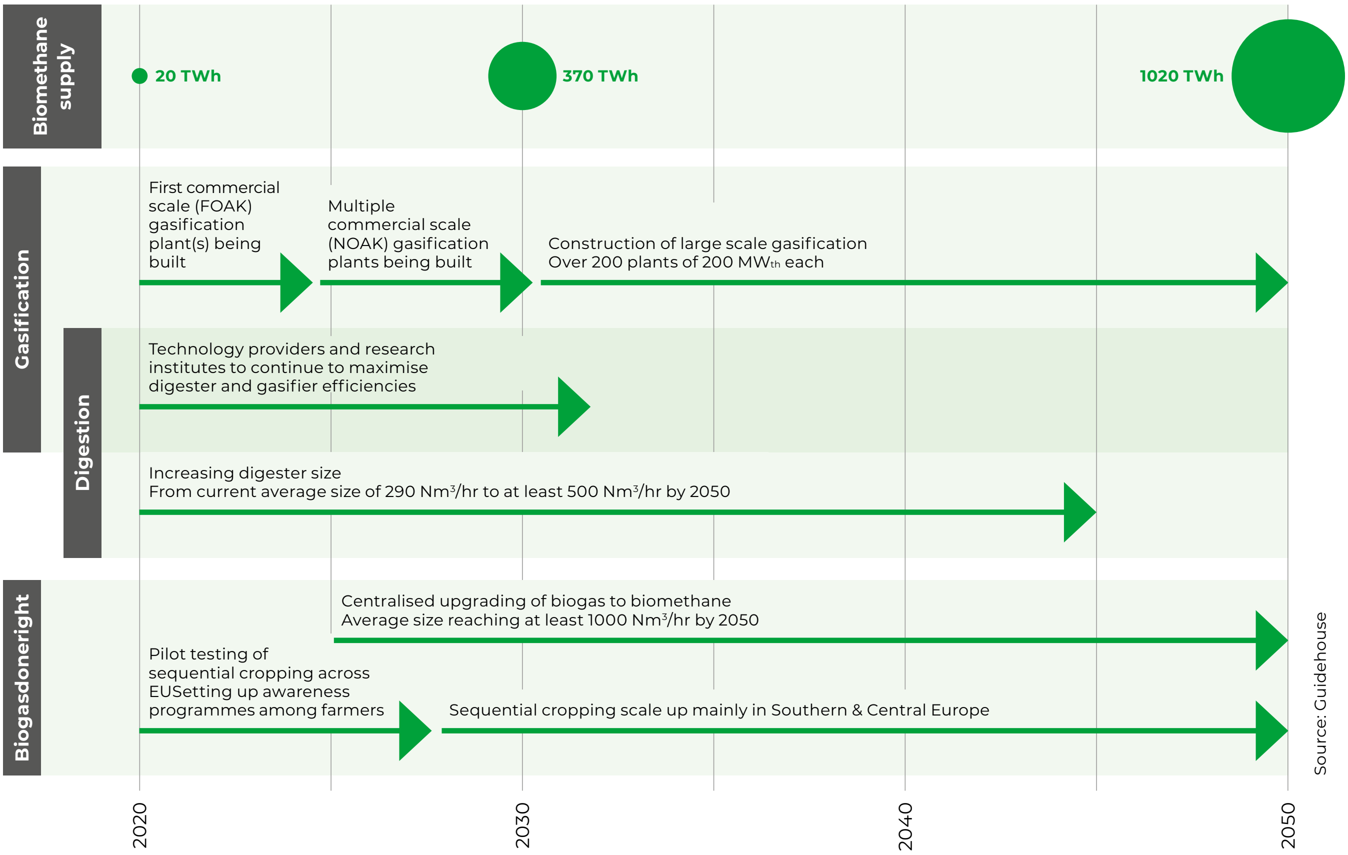
Today, the concept of Biogasdoneright is applied by hundreds of farmers in Italy and a growing number in France. Research is needed to test to what extent the concept can be implemented in more temperate parts of Europe as well. Large-scale training and awareness-raising programmes would need to be implemented 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 1020 TWh (95 bcm natural gas equivalent) can be mobilised by mid-century.

In addition to this, about 150 TWh (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.[16]

16 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.

Figure 4.
Critical timeline biomethane supply



2.1.2 Hydrogen deployment pathway

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.[17]

17 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).

→ 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.[18, 19]

According to the Hydrogen Roadmap Europe, the current use of hydrogen in the EU amounts to 339 TWh.[20] 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,[21] 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 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.[22] 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.[23]

An important precondition for a scale-up of blue hydrogen is CCS to be accepted by policymakers and societies in specific member states. Most EU member states have favourable attitudes towards CCS in their long-term climate strategies.[24] However, when transposing the EU CCS Directive, some member states introduced limitations on the CO_2 storage potential.[25] For example, in Germany, CO_2 storage is currently not permitted and is also not foreseen for the future, although the German hydrogen strategy still needs to be published. In the countries where CCS is embraced as an emissions abatement technology, the general sentiment is that it should be used as a transition option with a positive effect on the cumulative CO_2 emissions, until a fully renewable solution is available.

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 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

18 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.
19 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/).
20 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.
21 Roads2HyCom, 2007. *Industrial surplus hydrogen and markets and production*, http://citeseerx.ist.psu.edu/viewdoc/summary?doi=10.1.1.477.3069
22 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.
23 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.
24 Based on analysis of existing national legislation and long-term government strategies in Navigant, *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*, 2019, section E.4.
25 Navigant (2019), *Gas for Climate: The optimal role for gas in a net-zero emissions energy system*.

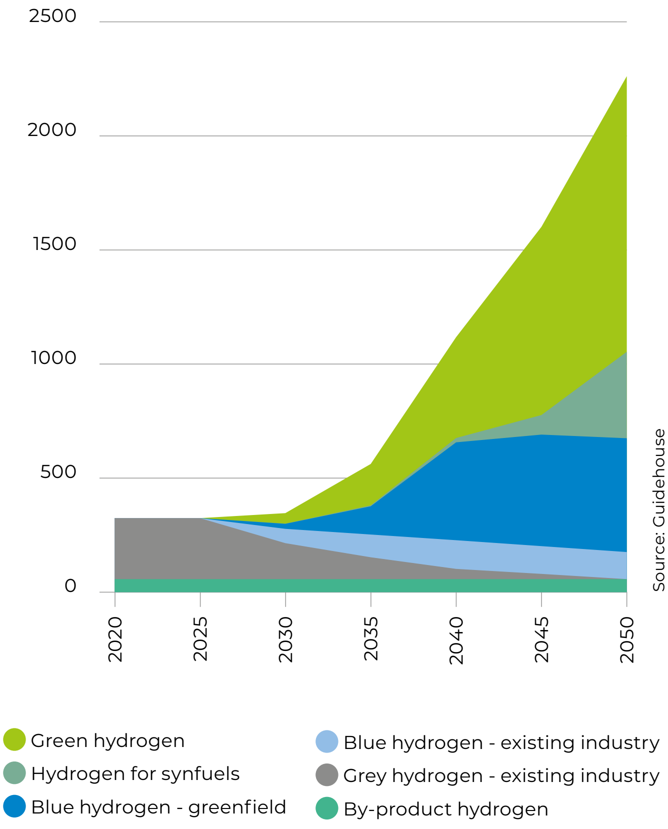
low carbon hydrogen. After 2050, part of the blue hydrogen production infrastructure can continue to be used to produce climate positive hydrogen using biomethane as input for blue hydrogen plus generating much-needed negative emissions.

In the Accelerated Decarbonisation Pathway, an EU ETS price of €55/tCO_2 by 2030 is expected, which is likely to enable a more rapid conversion of conventional hydrogen plants to CCS and also make greenfield blue hydrogen plants competitive with SMR plants without CCS. This development would likely see a significant share of the remaining grey hydrogen plants retrofitted with CCS by 2040, providing a decarbonised hydrogen supply to existing end uses of about 125 TWh by 2040. Because the demand for decarbonised hydrogen is already substantial before 2040, for example, for use in the power sector, steel, and as a feedstock for methanol production, greenfield blue hydrogen plants will be needed to satisfy this demand. Green hydrogen alone will not be able to meet all of this. New blue hydrogen plants based on ATR technology could ramp up and deliver around 430 TWh of hydrogen 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. Much of the infrastructure is already in place. Gas TSOs could step up to transport the CO_2, potentially repurposing offshore gas pipelines.

The increased emission reduction target of the EU Green Deal would see the power sector decarbonise rapidly, 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 large ground-mounted solar PV systems can already deliver power well below €20/MWh_e.[26] From 2030 onwards, the increasing offshore wind capacity in the Northern Seas is expected to grow from around 80 GW in 2030 to over 200 GW by 2050 and 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. The upcoming EU strategies with respect to gas decarbonisation and sector integration (integrated energy system) should take this into account.

Green hydrogen supply could reach around 50 TWh by 2030 (20-25 GW installed capacity). After 2040, green hydrogen surpasses the production of blue hydrogen at around 500 TWh due to rapid cost reductions. Green hydrogen's production costs reach €51-66/MWh by 2040, making it competitive with the production of blue hydrogen in SMR or autothermal reforming plants with CCS. Costs can decrease much further and more rapidly if mainly electrolyser cost and renewable power costs decrease faster, which increasingly would seem to be the case. Such developments are explored in Chapter 5.

Figure 5. Hydrogen supply in the Accelerated Decarbonisation Pathway (TWh)



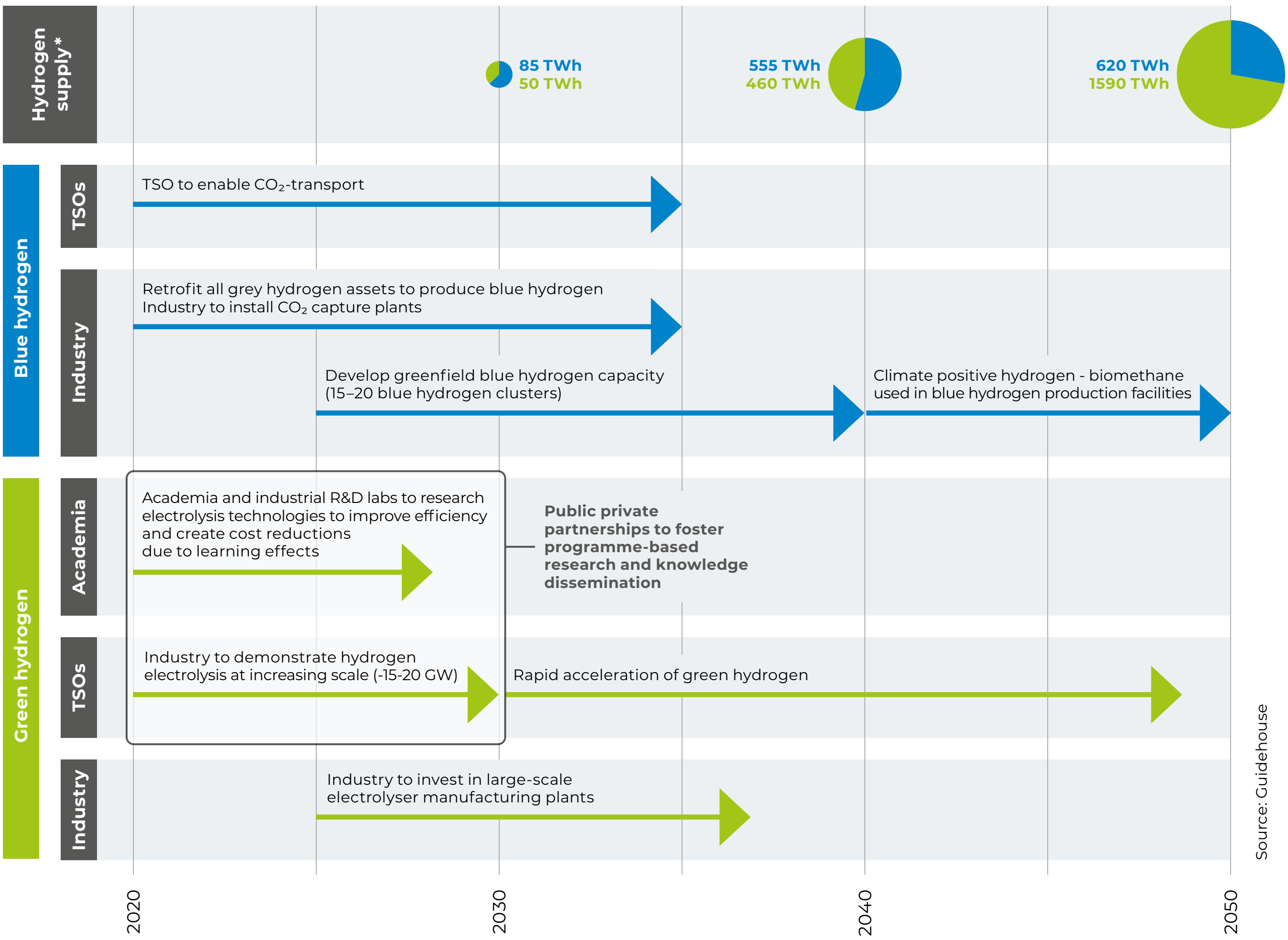
Note that the supply in this figure exceeds the 1,710 TWh of the Gas for Climate 2050 Optimised Gas end state because supply is included from petrochemicals, which was previously out of scope, and production of synthetic fuels.

26 T-Solar, *Photovoltaic Auction Analysis Portugal 2019*, September 26, 2019, https://www.tsolar.com/en/news/photo-voltaic-auction-analysis-portugal-2019.html.

To achieve the highest possible rate of improvement, public-private partnerships could be conducted to foster programme-based R&D. These would see universities working together with industrial R&D departments on improving electrolysis technologies, while industry demonstrates electrolysis at an increasing scale to drive economies of scale and the learning curve.

With the Accelerated Decarbonisation Pathway, the volume of hydrogen in the Gas for Climate 2050 Optimised Gas end state can be exceeded with a green hydrogen supply of around 1,600 TWh and a blue hydrogen supply of around 600 TWh (Figure 5). When sufficiently stimulated, 500–600 GW of green hydrogen capacity could be reached by 2050. This will include a combination of distributed and centralised hydrogen production sites with conversion efficiencies of around 80% by 2050.

Figure 6.
Critical timeline hydrogen supply



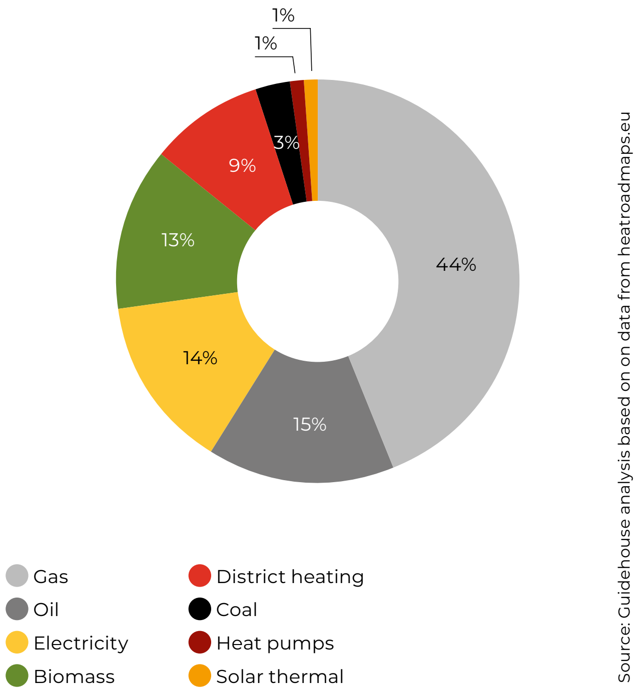
** Note that the supply in this figure exceeds the 1,710 TWh of the optimal gas end-state because supply is included from petrochemicals (previously out of scope), and production of synthetic fuels.*

2.2 Decarbonisation of EU energy demand

2.2.1 Buildings decarbonisation pathway

Buildings are Europe's largest energy consumer, responsible for about 40% of the EU's energy consumption.[27] 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%.[28] The availability of energy sources and access to infrastructure play a large role here.[29]

Figure 7. Current share of energy carriers in heating and domestic hot water in the built environment[31]

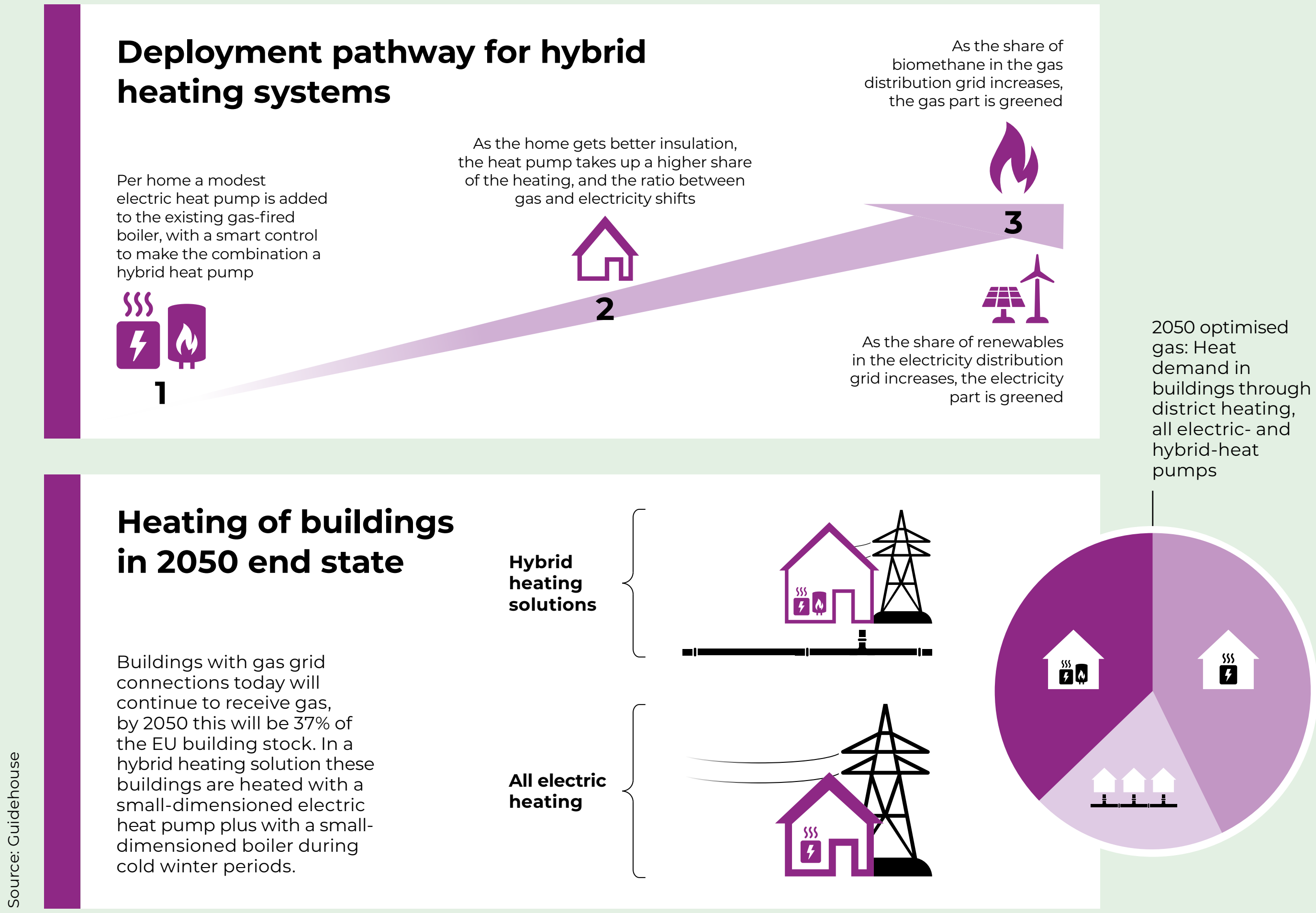


Currently, the built environment uses about 3,600 TWh[30] for heating and domestic hot water. Almost half of this energy demand is from natural gas, while the other half is from a variety of energy carriers, like oil, biomass, electricity, and district heating (Figure 7). When gas is used, it is almost 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.

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[32] 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

27 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.
28 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.
29 E.g. the Netherlands has a huge natural gas resource in the northern part of the country.
30 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.
31 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.
32 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.

Figure 8.
The Gas for Climate future for buildings



technologies such as heat pumps. However, the current average EU annual weighted energy renovation rate[33] for residential and non-residential buildings is only around 1% with a limited share of deep renovation.[34, 35] 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.

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. In times of abundant renewable

33 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.

34 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

35 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.

electricity and not too low temperatures, heat will be provided by the electric heat pump, in times of low temperatures or limited availability of renewable electricity, gas will provide flexible peak capacity (Box 1). 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 (see Chapter 5).

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,[36] 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.

Box 1. 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 focussing on information and knowledge dissemination, standardising the application of this combination, and ensuring the option is considered when developing renovation plans.

36 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/.

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:[37]

The Accelerated Decarbonisation Pathway requires a renovation rate of 2.5%–3% per year

- Increase renovation speed of all buildings, with a substantial energy improvement component.
- Improve the depth of renovation, going from light and medium renovations to medium and deep renovations.
- 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 9).

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.[38]

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.

37 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.

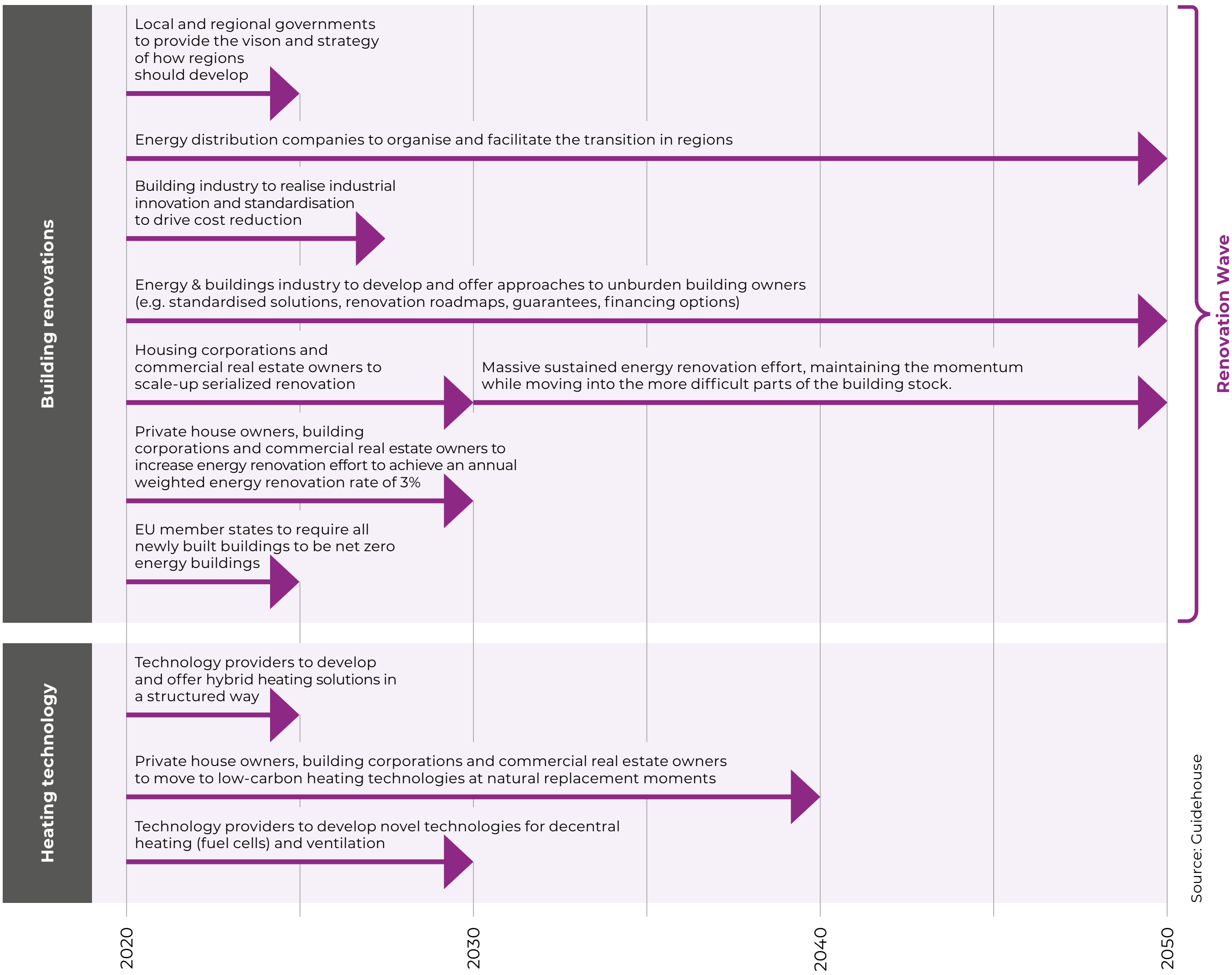
38 Klimaatakkoord, 2019. *Klimaatakkoord*, 'Renovatieversneller' mentioned multiple times in pages 19-34. Available at: https://www.klimaatakkoord.nl/klimaatakkoord/documenten/publicaties/2019/06/28/klimaatakkoord.

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.

Figure 9.
Critical timeline buildings



Source: Guidehouse

2.2.2 Industry decarbonisation pathway

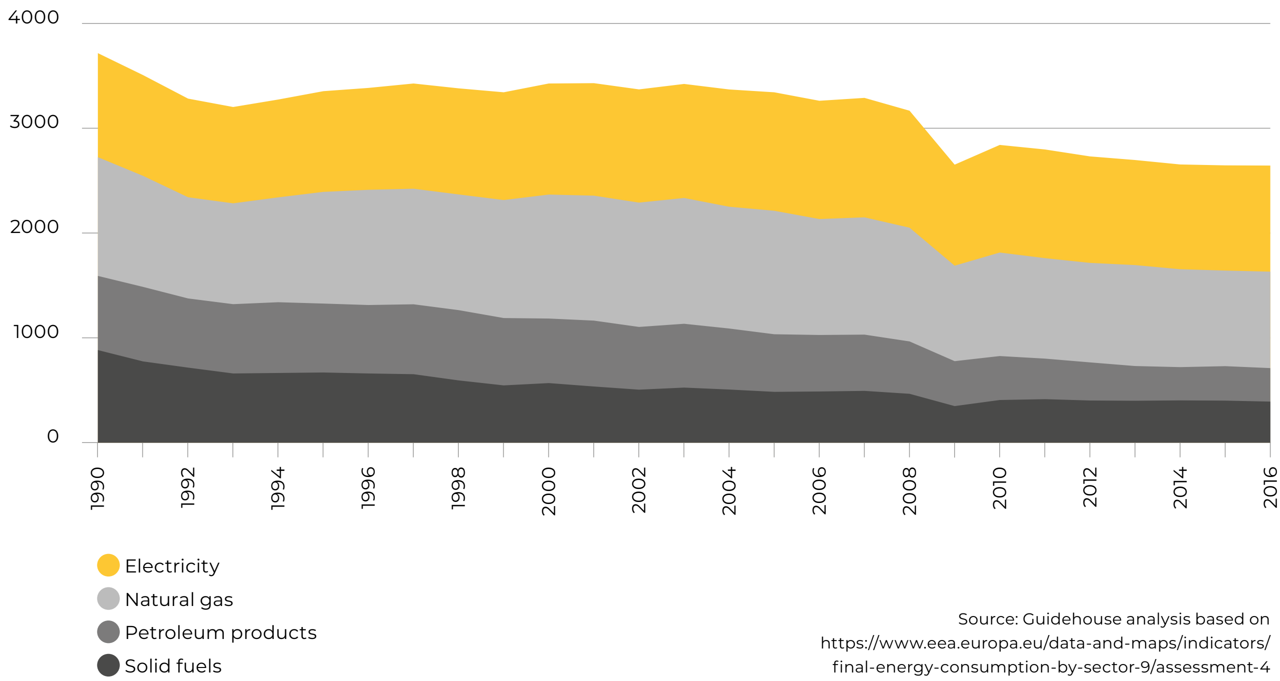
The industry sector is important to the EU economy in terms of added value and job creation. The sector also has a high energy demand and greenhouse gas emissions, despite a strong reduction since 1990. In 2016, industry accounted for 22% (2,650 TWh) of the EU's final energy consumption. Electricity (1,010 TWh) and natural gas (920 TWh) are the most important energy sources, and their relative share has grown (Figure 10).[39]

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.[40]

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.

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

Figure 10. Development of final energy consumption in EU industry sector (TWh)



Source: Guidehouse analysis based on https://www.eea.europa.eu/data-and-maps/indicators/final-energy-consumption-by-sector-9/assessment-4

39 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.

40 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.

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.

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.

Heavy industry currently uses substantial quantities of hydrogen. The sector's current consumption in Europe is around 230 TWh of hydrogen, half of which is used to produce ammonia, an important material in the fertiliser industry.[41]

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).[42]

The EU industry requires 70 TWh–100 TWh of renewable and low carbon gases by 2030

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

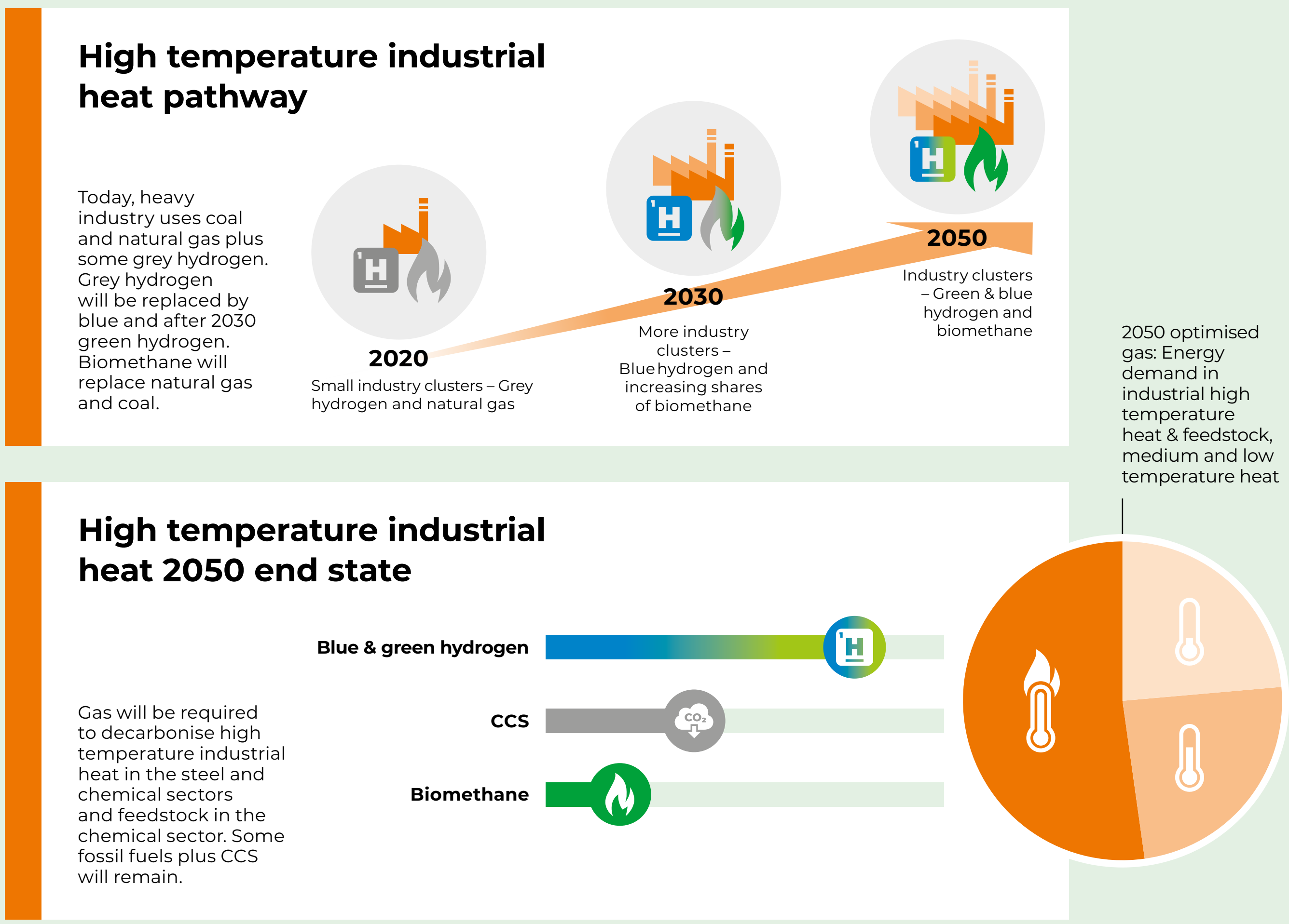
41 http://www.certifhy.eu/images/D1_2_Overview_of_the_market_segmentation_Final_22_June_low-res.pdf
42 A CfD is a contract between an industry company investing in a breakthrough technology and a government body. The idea is that the company is paid by the government body, over a predetermined number 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 CO_2 abatement costs of a particular technology.

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.

Figure 11.
The Gas for Climate future for industry



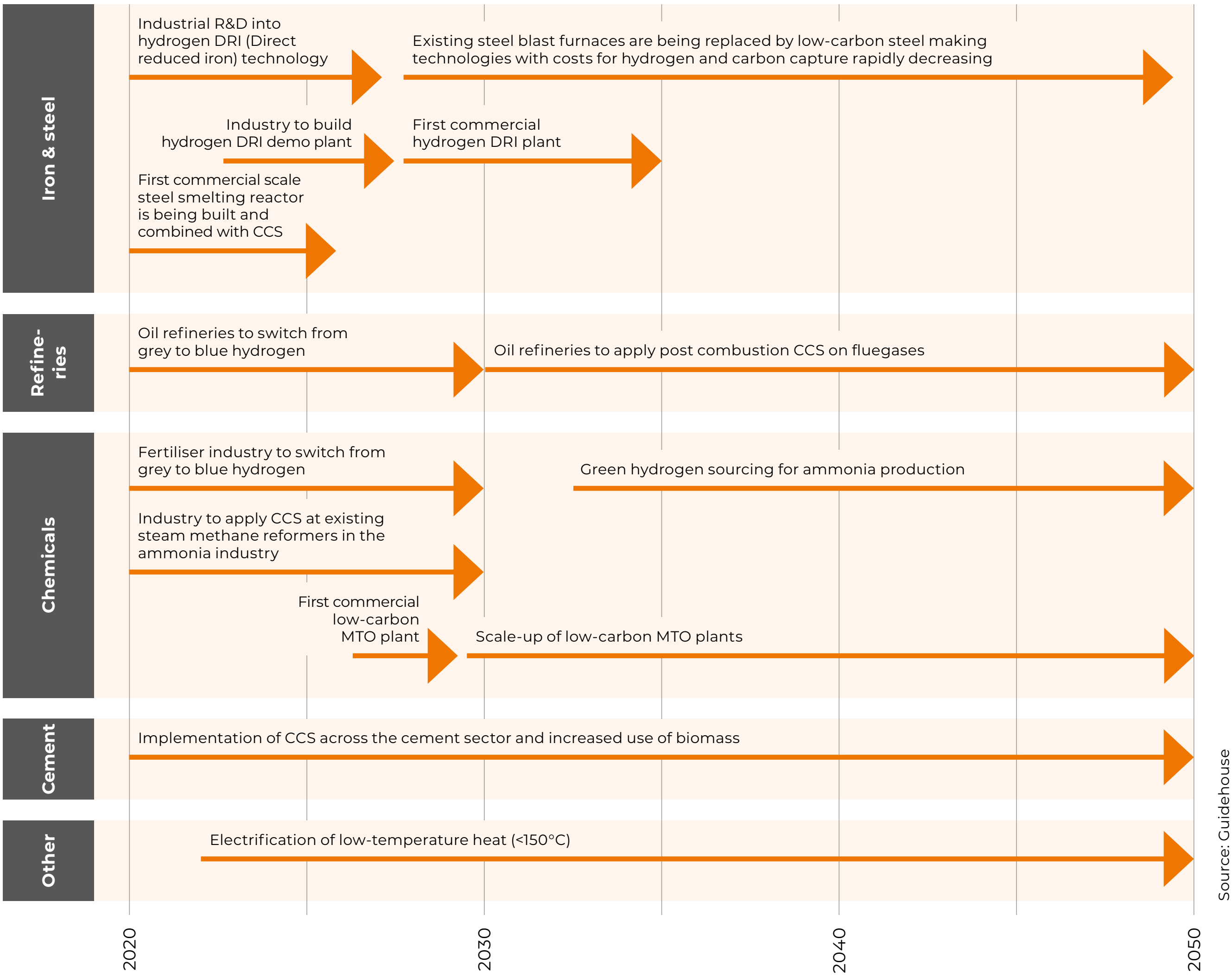
Source: Guidehouse

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.

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.

Figure 12.
Critical timeline industry



Connection to EU industrial policy

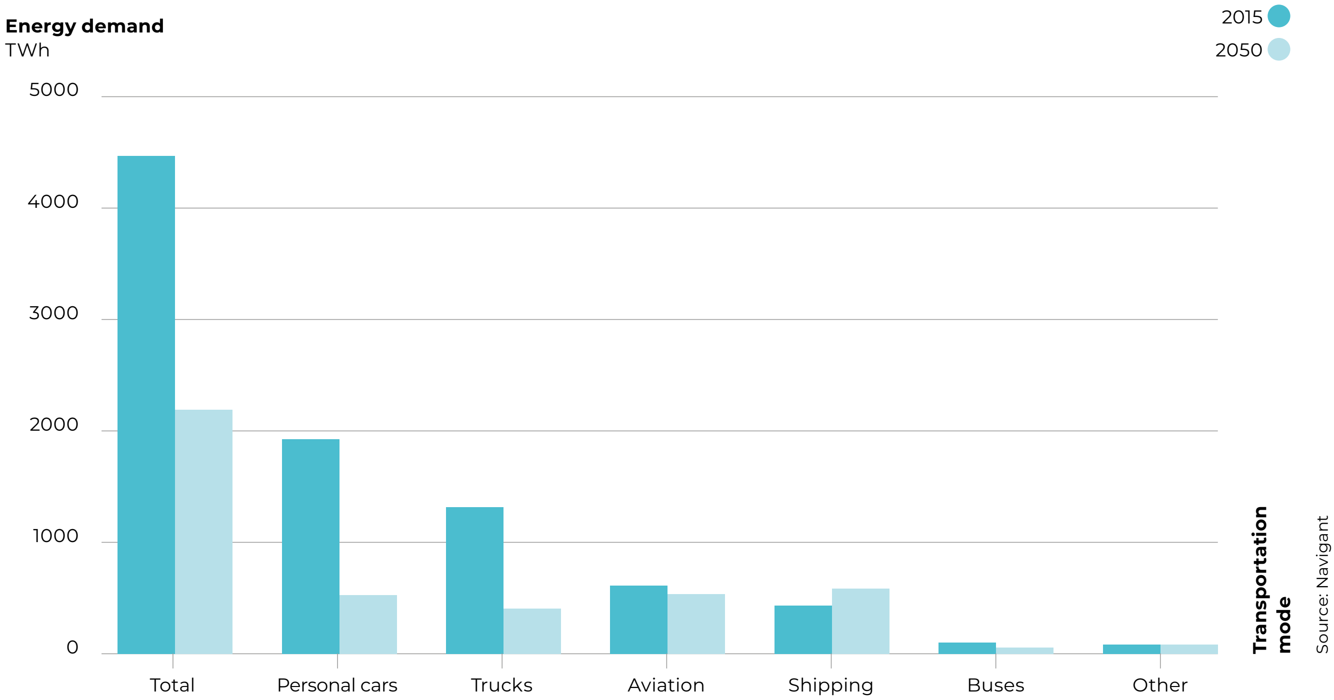
The acceleration of renewable and low carbon gas deployment in the decarbonisation in EU industry, as described in our Accelerated Decarbonisation Pathway, fit well with the EU Industrial Strategy, which was published in March 2020. It aims to reap the opportunities to start moving in the 2020s, while keeping EU industry competitive on the world markets. A higher CO_2 price (€55/tCO_2) by 2030 in the Accelerated Decarbonisation Pathway, gradually increasing afterwards to €150/tCO_2 by mid-century) combined with the carbon border adjustment mechanism announced in the European Commission's Communication on the European Green Deal is essential in enabling this.

2.2.3 Transport decarbonisation pathway

In 2017, 27% of total EU greenhouse gas emissions were related to transport. Since 1990, transport emissions increased by 28% (excluding international shipping).[43] 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 13). Most of the energy use in road transport is supplied via diesel (2,280 TWh) and gasoline (900 TWh). Energy use

Figure 13. EU final energy use in the transport sector for various subsectors in both 2015 and Gas for Climate 2050 Optimised Gas end state



43 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

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.[44]

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. An Accelerated decarbonisation Pathway towards the Gas for Climate 2050 Optimised Gas end state would develop as follows:

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. In addition, bio-compressed natural gas (bio-CNG) is a viable medium- to longer term option to lower the greenhouse gas intensity of heavy transport, also to stimulate an early development of the biomethane market. Bio-CNG passenger cars can be a relevant transitional decarbonisation option, especially Italy where a well-developed CNG car market and infrastructure exist today. It is likely that EVs will be more cost-effective for passenger cars by or shortly after 2030[45], after which bio-CNG may continue to be used in the truck segment next to hydrogen and bio-LNG.

While biomethane can play a role in road transport, by 2050 most biomethane will be used elsewhere in the energy system, where it has a higher societal value, including in the heating of buildings, and the production of dispatchable power and industrial heat and feedstock.

The societal costs for various low carbon vehicle fuel options are comparable, which 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.

Electrification is the key decarbonisation measure in road transport, but for heavy road transport hydrogen and bio-LNG or bio-CNG will be important energy carriers as well

Shipping

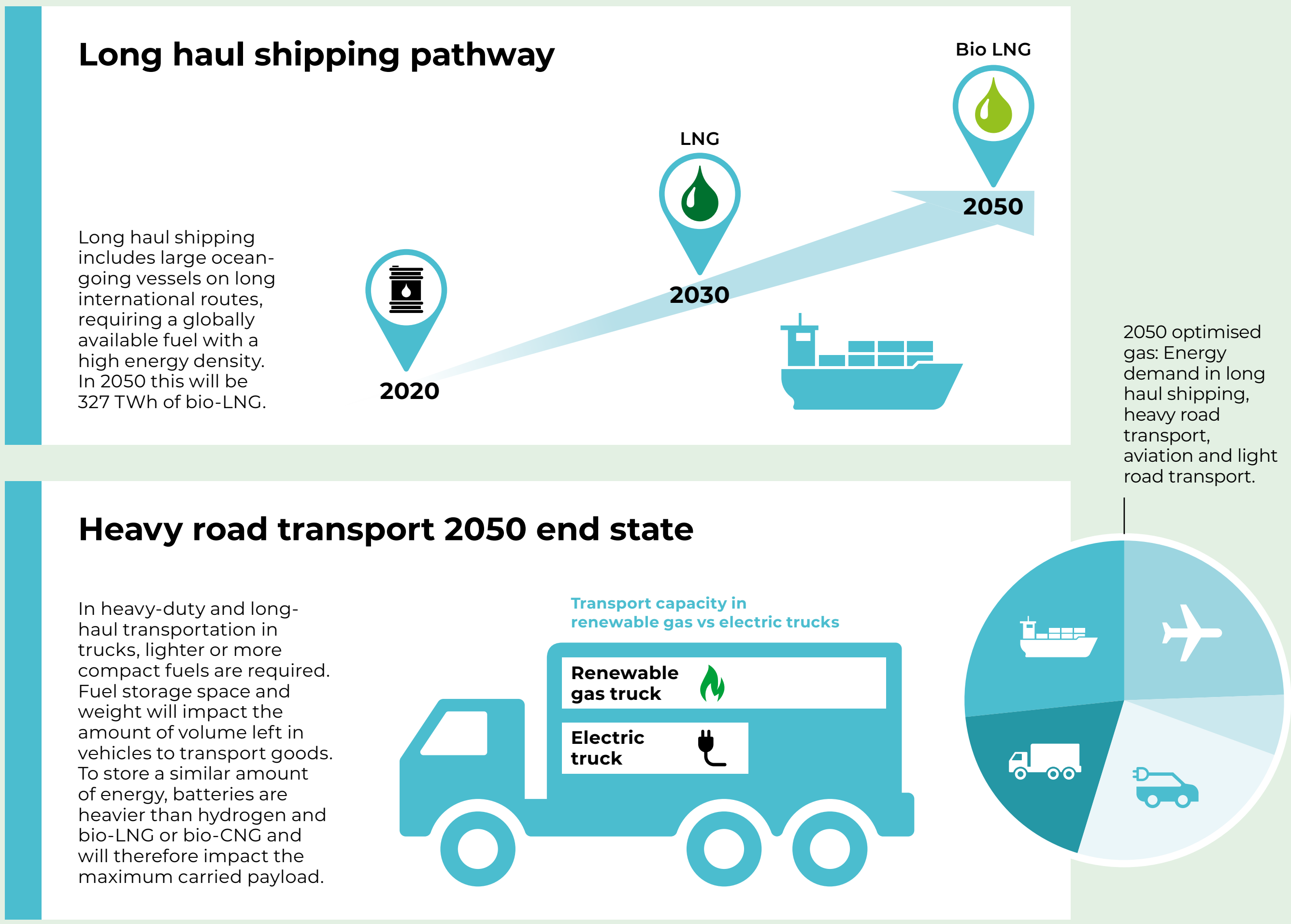
Many future fuel technologies are being considered for the shipping sector. Based on its analysis, Navigant envisions that all existing diesel and marine fuelled vessels will be replaced mainly by bio-LNG and battery electric vessels by 2050, avoiding the need to develop additional production routes 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.

44 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

45 Guidehouse calculations show that by 2030 the total cost of ownership of EVs can be 5-10% lower than ICE-passenger cars.

Figure 14.

The Gas for Climate future for transport



Source: Guidehouse

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.

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.[46] 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[47] 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,

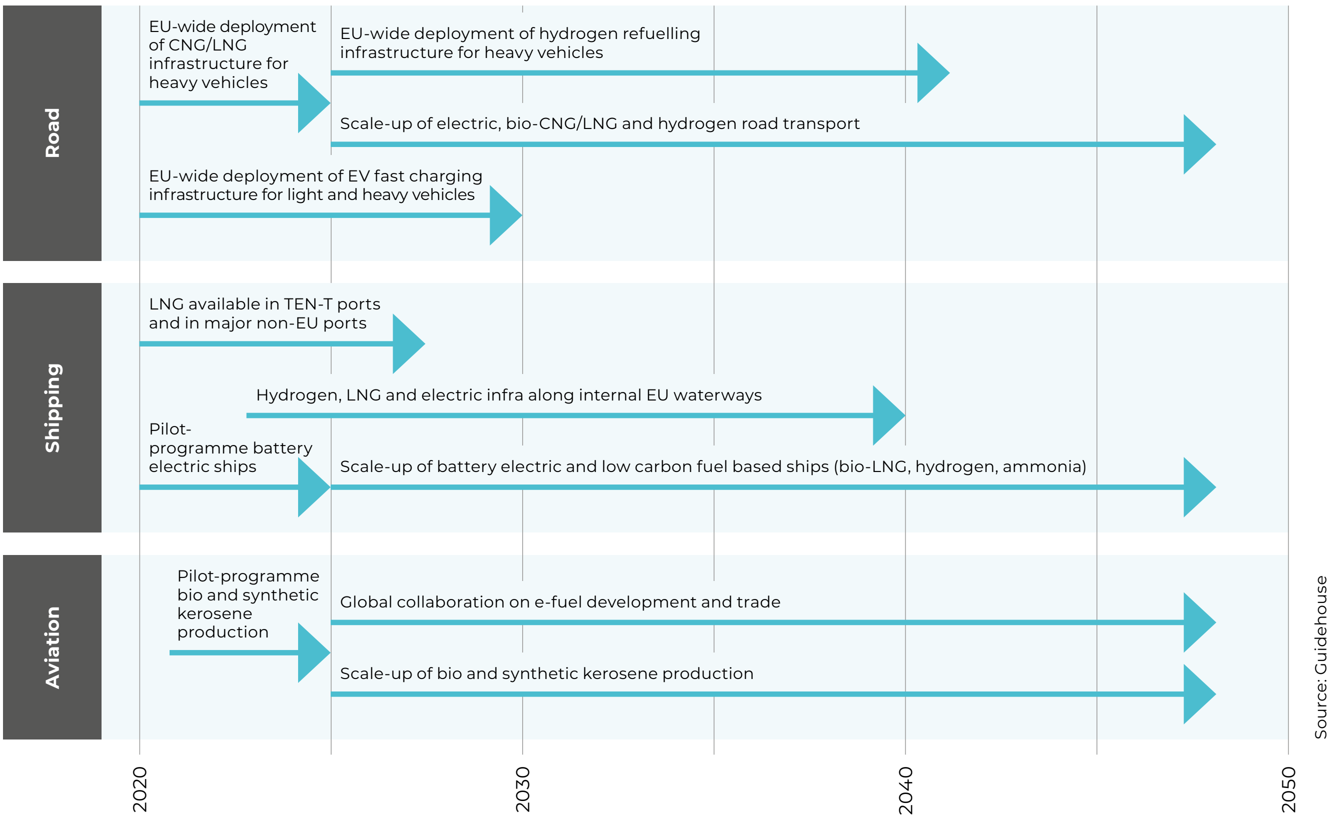
46 European Commission, *The European Green Deal*, 2019, https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf.
47 In 2018, battery costs per kWh have dropped by 85% since 2010. By 2030 experts foresee another 65% drop in battery costs compared to 2018, resulting in a cost level of €56/kWh. Source: Bloomberg NEF, *Electric Vehicle Outlook 2019*, 2019.

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.[48] This demand will be met by 267 TWh of bio jet fuel and 267 TWh of synthetic jet fuels based on hydrogen from electrolysis.

Figure 15.
Critical timeline transport



48 Transport & Environment, *Roadmap to decarbonising European aviation*, 2018

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

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 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.

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.

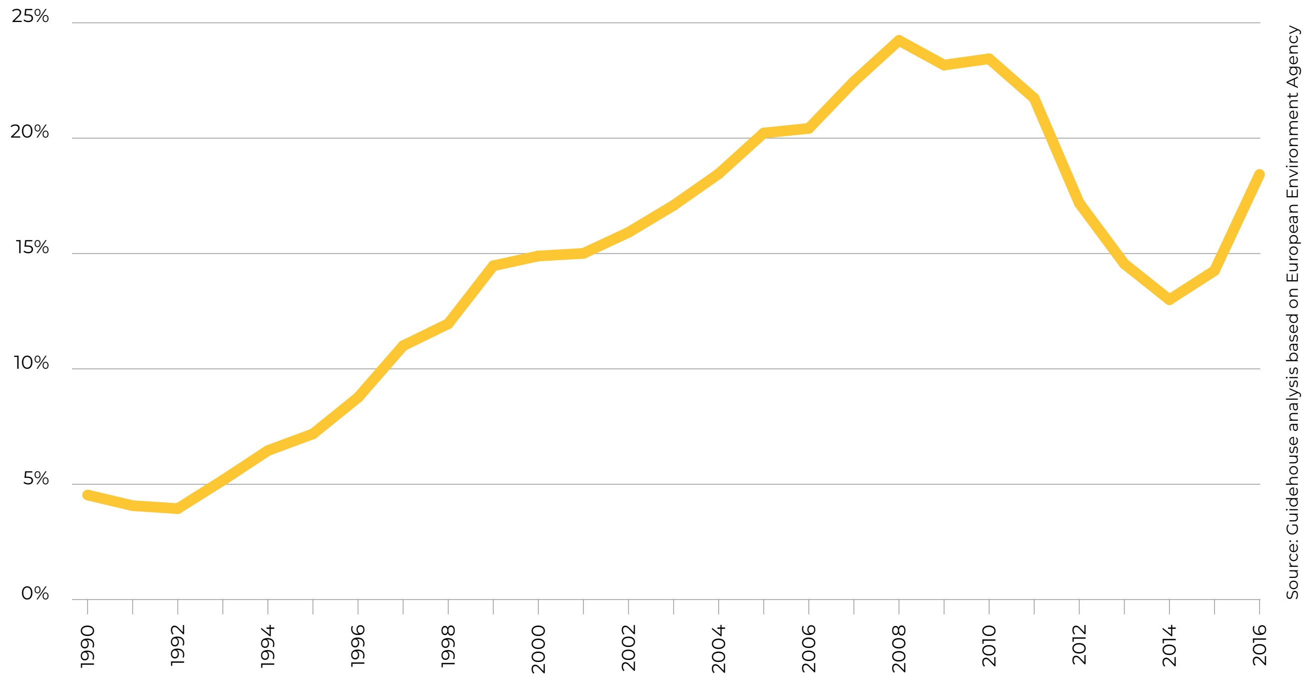
2.3 Decarbonisation of the EU power sector

The increasing electrification of the energy system is essential to achieving a net-zero emissions EU energy system. In combination with a large increase in variable renewable power production, this calls for a better integration of the use of electricity, heat, and low carbon gases and their respective infrastructures. A highly integrated energy system needs accompanying transportation networks. The electricity grid should enable direct use of sustainable electricity in those sectors where electrification is technically and economically feasible, thus avoiding energy conversion and the associated energy loss. Excess electricity should be used to produce green hydrogen, which can then be transported in the gas infrastructure and stored in existing storage infrastructure.

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.[49] 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.[50] The emissions intensity of electricity already dropped by 44% from 0.524 $kgCO_2/kWh$ in 1990 to 0.296 $kgCO_2/kWh$ in 2016.[51] 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 16).[52] At this moment, around 660 TWh of electricity (20%) is produced from around 1,330 TWh of gas, from which 1,160 TWh is natural gas and derived gases, and 170 TWh is biogas. The current installed capacity of gas-fired power plants is 220 GW.

49 Gross electricity production-based Eurostat, *Supply, transformation and consumption of electricity [nrg_cb_e]*.
50 Eurostat Statistics Explained, *Renewable Energy Statistics*, Eurostat, https://ec.europa.eu/eurostat/statistics-explained/index.php/Renewable_energy_statistics.
51 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.
52 European Environment Agency, *Overview of Electricity Production and Use in Europe*.

Figure 16. Share of natural and derived gases in gross electricity generation



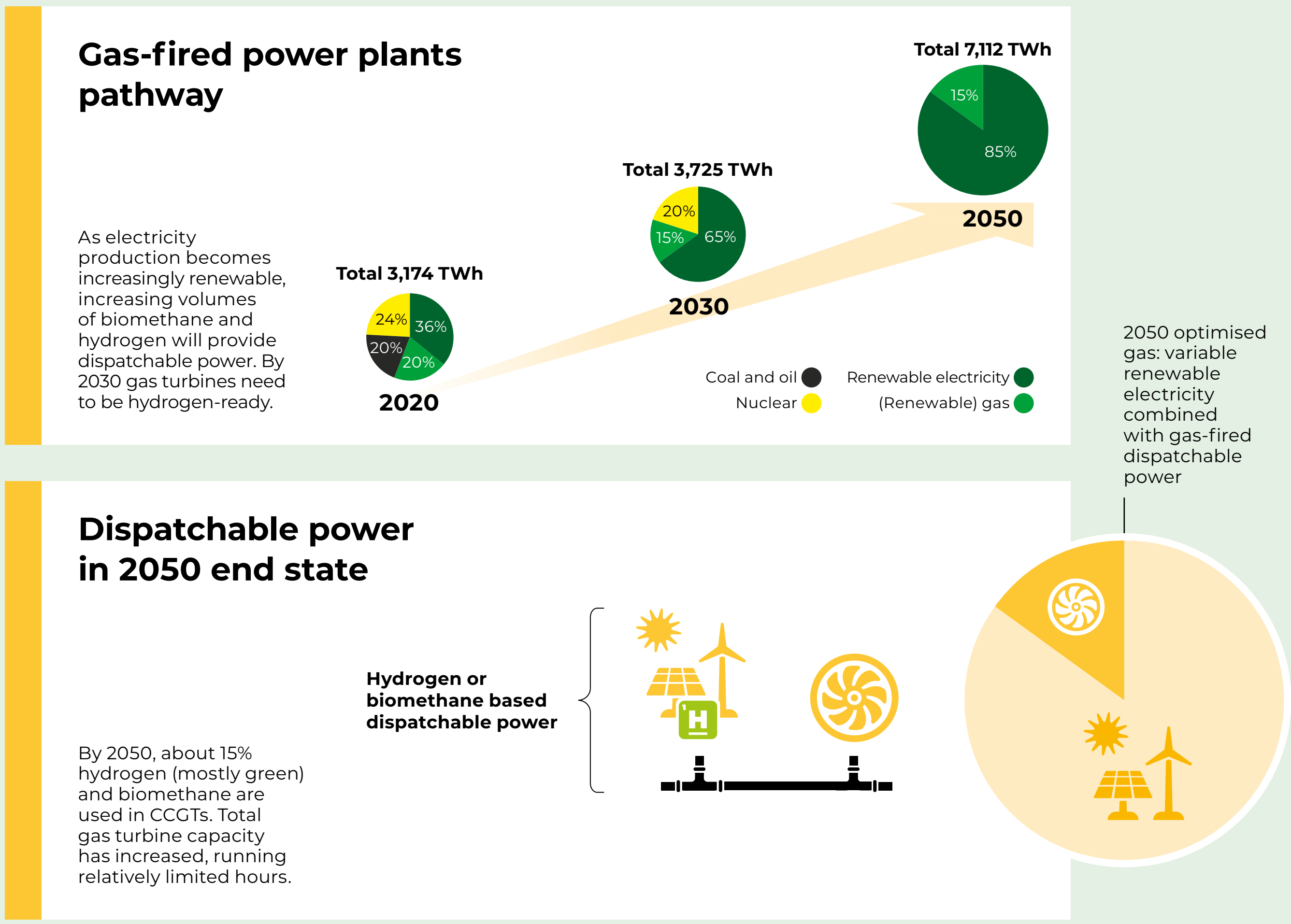
Decarbonisation of the EU power system implies fundamental changes in the way electricity will be generated, stored, and transported. Wind and solar will be the mainstay of future EU renewable electricity production, mainly in the form of direct available sustainable electricity, but also via dedicated 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 backup 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.

Decarbonisation of the EU power system suggests fundamental changes in the way electricity will be generated, stored, and transported

Renewable and low carbon gas like green hydrogen, stored in salt caverns and used in efficient gas-fired power plants can provide backup capacity in periods of insufficient renewable electricity

Figure 17.

The Gas for Climate future for power



Source: Guidehouse

supply.[53] 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.[54]

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.

53 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.

54 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.

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 gas-fired and nuclear power plants.[55] 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 flexible 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 to the higher efficiency combined cycle gas turbines (CCGTs).

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.

In the Accelerated Decarbonisation Pathway, 60%–70% of electricity will be generated by renewables in 2030

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[56]
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

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

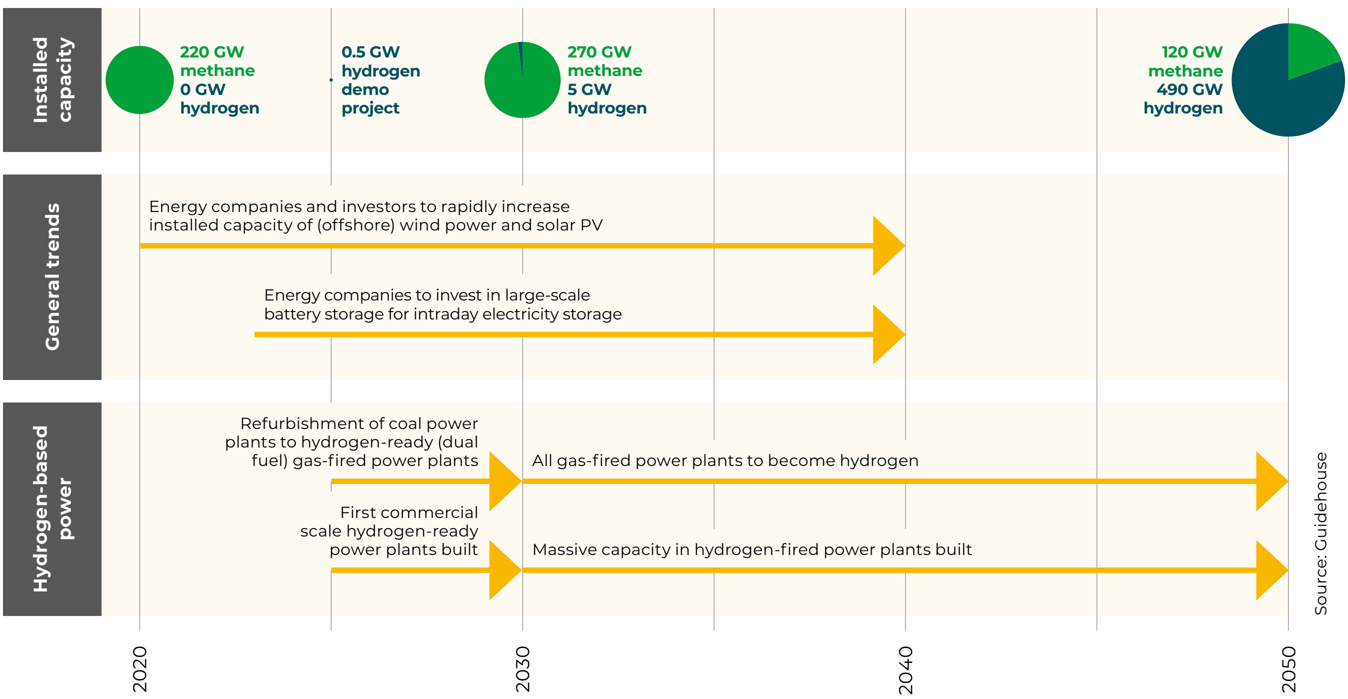
56 Also referred to as pre-combustion CCS.

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 18). 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.

Figure 18.
Critical timeline power



2.4 Gas infrastructure developments 2020 to 2050

The energy system of the future is expected to require strong electricity networks as well as a strong gas infrastructure, including storage facilities, to secure supply of renewable energy in the form of both molecules and electrons. The respective infrastructures for gas, electricity, and heating will need to be coordinated and planned in a more integrated way to make use of all their offered advantages through sector coupling. Furthermore, integrated network planning for electricity and gas networks is essential to prevent inefficient and costly bias towards one form of network or the other.[57]

ENTSOG and ENTSO-E have already started co-ordinating their respective Ten Year Network Development Plans (TYNDP) by creating joint scenarios capturing the existing interlinkages between both sectors and the long-term development of integrated infrastructure. In the future, further benefits could be realised in ensuring greater coordination between electricity and gas TSOs (and DSOs) on the member states level.

In the Accelerated Decarbonisation Pathway, biomethane and hydrogen volumes make up 10% of total gas consumption in the EU by 2030, followed by a rapid and accelerated scale-up between 2030 and 2050. Electricity demand will increase from around 3,200 TWh in 2020 to around 3,700 TWh in 2030 and almost 7,000 TWh in 2050. At the same time, it will become more volatile due to an increase in the use of electricity for heating of buildings. Electricity supply will also increasingly fluctuate. In 2030, 40%–50% of all electricity comes from intermittent sources, increasing to over 80% in 2050.

Up to 2030, gas infrastructure will mainly be used to transport, store, and distribute biomethane, 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 be injected in into the high pressure grid facilitated by reverse flow technology to be transported to different regions and across borders through transmission grids. Between 2040 and 2050 a notable production of power to methane could be expected, using biogenic CO_2 captured in large biogas digesters and green hydrogen produced onsite. This methane will be injected in existing gas grids. Pure hydrogen will initially be used mainly in industrial clusters that already use hydrogen today. Up to 2030, only a limited quantity of hydrogen will flow through gas grids, often blended with natural gas.

Electricity infrastructure will be adapted to cope with increased volumes of centrally and locally produced sustainable electricity. Fluctuations in electricity supply will still mainly be absorbed by the electricity sector themselves. The need for dispatchable electricity from gas-fired power plants will increase, but as the total demand for methane decreases, no major adaptions to gas infrastructure will be needed. For the same reason, demand for gas as in terms of backup for heat networks in colder periods will not lead to major adaptions in the gas infrastructure.

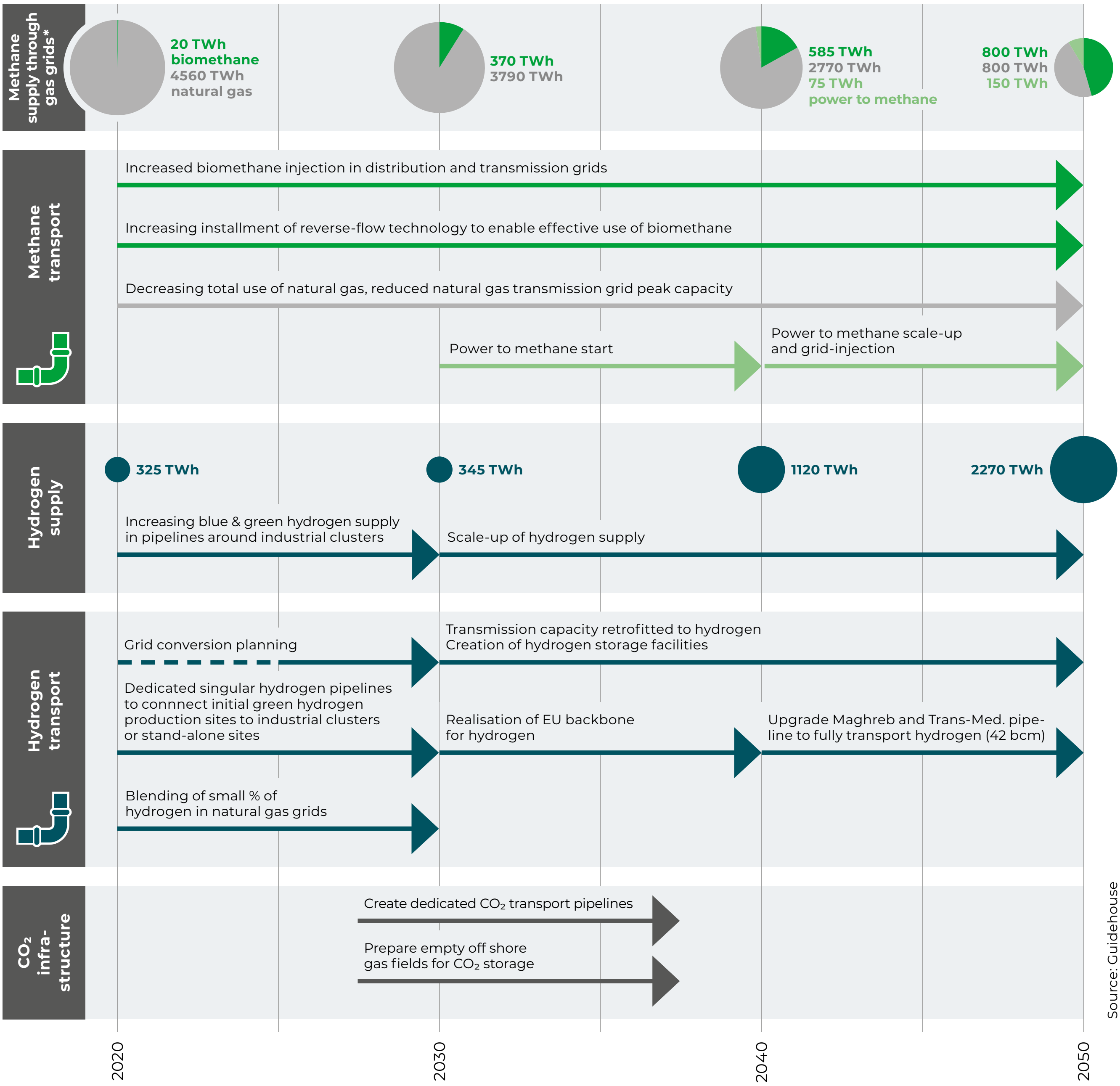
Around 2030, the scale-up of green and blue hydrogen and its increased consumption in industrial sites outside industrial clusters will require the creation of dedicated regional or national hydrogen infrastructures. Gradually, around 2035, national hydrogen backbones, as already proposed for the Netherlands[58] and Germany[59], can be connected to create a dedicated European hydrogen backbone infrastructure. Such infrastructure would use existing natural gas pipelines, especially at routes with parallel pipes and in regions where natural gas infrastructure becomes available due to

57 For further details on the regulatory barriers, see European Commission (DG ENER) Study *Potentials of sector coupling for decarbonisation – assessing regulatory barriers in linking the gas and electricity sectors in the EU*, Frontier Economics, CE Delft, Thema Consulting Group (2019).

58 Gasunie, *Moving towards 2030 and 2050 with hydrogen*, https://www.gasunie.nl/en/news/meet-the-gasunie-hydrogen-team-at-e-world-in-essen/$4392/$4393

59 FNB-Gas, https://www.fnb-gas.de/fnb-gas/veroeffentlichungen/pressemitteilungen/fernleitungs-netzbetreiber-veroeffentlichen-karte-fuer-visionaeres-wasserstoffnetz-h2-netz/ (in German)

Figure 19.
Critical timeline infrastructure



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

a gradual decrease in natural gas transport. These retrofitted pipelines would be complemented with newly built hydrogen pipes where needed.[60] As the share of intermittent electricity, the number of heat networks, and the number of hybrid heating solutions increase, the need for hydrogen storage for seasonal use increases too. 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. Existing salt caverns should be made available for hydrogen storage, and an assessment of the need for additional salt caverns should be made as soon as possible, given the long lead time to create those; this should form an integral part of future energy infrastructure planning.

Figure 19 details the most important gas infrastructure developments between 2020 and 2050.

The rest of this section details the Accelerated Decarbonisation Pathway, describing the situation today and developments in each of the three decades up to 2050.

2.4.1 The role of gas grids in Europe today and in the future[61]

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.[62] 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.[63] The grids foster security of supply and diversification of sources.

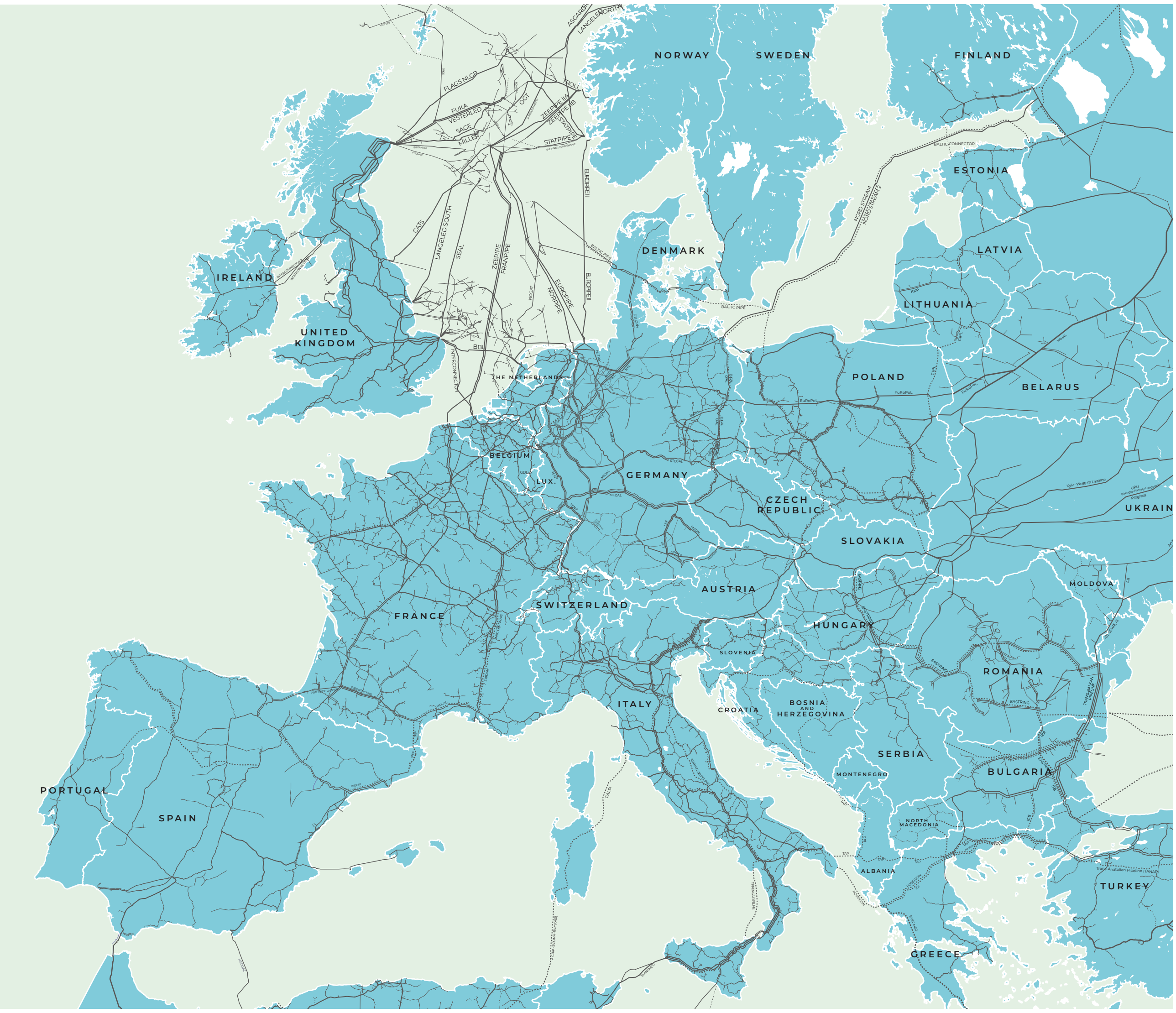
Long-distance gas transport occurs through large diameter transmission lines operated at high pressure (usually from 40 up to 100 bar, depending on the country). This network is used to import gas from outside the EU and to interconnect EU member states' national gas networks. Medium pressure pipelines (between 8 and 40 bar) are used to distribute gas to a dense network of low pressure distribution grids (up to 16 bar) delivering gas to end consumers.[64] The transmission network consists of about 260,000 km of high pressure transmission pipelines and medium pressure pipelines operated by around 45 TSOs. Figure 20 displays this network.

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.

60 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
61 Section largely taken from Navigant, *Gas for Climate*, 2019
62 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.
63 Eurostat, *Natural gas supply statistics*, https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Natural_gas_supply_statistics&oldid=447636#Supply_structure, 2020
64 What low, medium and high mean varies depending on the country

Figure 20. Natural gas transmission networks in Europe[65]



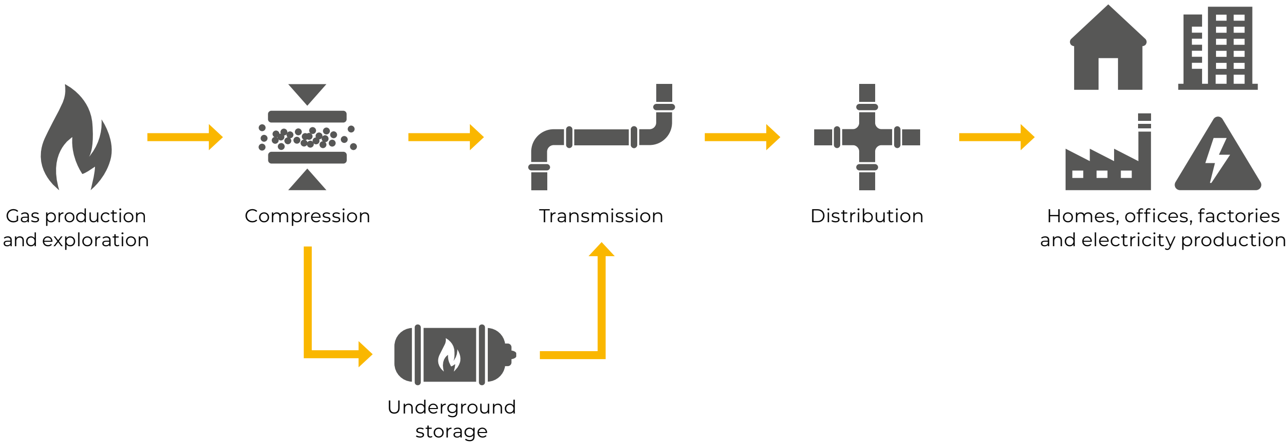
Source: ENTSOG

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. 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.[66]

65 ENTSOG, see https://transparency.entsog.eu/
66 The Nordstream pipeline has an inlet pressure of 220 bar, see http://www.gazprom.com/projects/nord-stream/

Figure 21. 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

Gas network offers flexibility and can deal with widely differing volumes of gas

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.

2.4.2 Gas infrastructure developments 2020 to 2030 under Accelerated Decarbonisation

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 natural gas equivalent) 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[67] 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 in Appendix 1, most biomethane production (this study estimates two-thirds of biomethane produced through anaerobic digestion) 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 with a direct connection 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 older 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, gas boilers could be gradually replaced by hybrid heat pumps, as described in section 2.2.1. Navigant expects that each EU member state can produce sufficient biomethane to meet demand in existing buildings with existing gas grid connections by 2050. This means that distribution grids in 2050 will be used for biomethane, and regional transport pipes will still be required to transport biomethane supply from 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.

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

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.

67 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

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. It would be optimal if there is third-party access to these privately operated hydrogen networks. Large industrial hydrogen projects will require a solution to transport CO_2 to storage locations. In cases where industrial clusters are located close to depleted gas fields below seabeds, e.g. below the North Sea, it makes sense to construct new, dedicated CO_2 pipes. A possibly more costly 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). Where larger quantities of green hydrogen would already be produced in 2030, local or regional dedicated hydrogen pipelines may be needed. Around 2030, it is expected that a larger scale-up of green hydrogen will require the gradual construction of regional and national hydrogen backbone infrastructures which during the 2030s would be connected into 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.[68] Blending-ready networks can also connect production sites where biomethane is produced with a small percentage of hydrogen, 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). Furthermore, a downstream separation of the hydrogen from the blended gas stream through separation membranes for instance could in the future become a possible option to adapt to purity demands of sensitive customers.

The expected scale-up of blue hydrogen production at industrial clusters to replace existing grey hydrogen 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 mainly be used locally and regionally up to 2030. Blending hydrogen in gas 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 could be marketed.[69]

68 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

69 For further details on the impact of biomethane and hydrogen in the European gas infrastructure, see European Commission (DG ENER) Study *Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure*, Trinomics B.V (2019)

↑
The Jupiter 1000 project, coordinated by GRTgaz, is the first industrial demonstrator of Power to Gas in France with a power rating of 1 MWe, converting renewable power surplus into green hydrogen and syngas for storage.

↑
A Power to Gas-plant in Prenzlau (Brandenburg), operated by ENERTRAG AG, in which electricity generated by wind turbines is converted into hydrogen and injected into the gas network of ONTRAS. The plant has a production capacity of 120 m³/h.

Hydrogen injection into the natural gas transmission network of Snam, directly supplying a pasta factory and a mineral water bottling company that both operate locally.
←

Storing hydrogen

Due to the relatively low energy density of hydrogen when compared to natural gas, more storage space is needed to store the same amount of energy. Storing hydrogen in large quantities will be a large challenge up to 2050, when as much as 2,270 TWh of hydrogen could be in our energy system in the Accelerated Decarbonisation Pathway. To achieve the same level of energy security as we have currently with natural gas, roughly 1.5 times the amount of storage would be needed compared to today, only considering hydrogen storage needs.[70] Adding storage needs for biomethane this figure would be larger.

Currently, salt caverns are an accepted method to balance the gas demand in our energy system and are filled and emptied in cycles of weeks to months. These salt caverns would also be well suited to store hydrogen.[71] The level of storage that would be needed is further influenced by the differences in production across the years, and whether this coincides with demand. When most of the hydrogen production in Europe is solar PV-based, more storage will be needed compared to balance the supply side with the demand pattern over the year. Depleted gas fields and aquifers could also play a role as large scale storage options for hydrogen but are significantly more costly than salt caverns.[72] Liquid storage options like ammonia or liquid organic hydrogen carriers can also be considered, but these storage costs are estimated to be higher than the production cost of hydrogen itself and may only be sensible in combination with large-distance transport.

2.4.3 Gas infrastructure developments 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 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. Around 2030 regional or national hydrogen backbone infrastructures start to emerge, possibly somewhat earlier in north western Europe and somewhat later in other parts of Europe. 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, partly through repurposing from methane to hydrogen.

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 an

70 Currently, there is about 5,000 TWh of natural gas in the EU's energy system. Due to the energy density of hydrogen being about three times lower, three times more space is needed to store the same amount of energy as natural gas. Because there is already enough storage space in the EU to balance the 5,000 TWh of demand for natural gas (roughly twice the amount of H_2 in 2050 in our AD Pathway), the amount of storage needed will be about 1.5 times higher. Bloomberg NEF (2020). *Hydrogen Economy Outlook: Key Messages*. https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

71 Bloomberg NEF (2020). *Hydrogen Economy Outlook: Key Messages*. https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

72 Gas fields are more expensive compared to storage in salt caverns because not all infrastructure is in place yet to facilitate the storage operations; gas platforms will first need to be redeveloped to make it suitable for large scale hydrogen storage. Garcia et al. (2016). *Expert Opinion Analysis on Renewable Hydrogen Storage Systems Potential in Europe*, Energies 2016, 9, 963; doi:10.3390/en9110963.

energy unit of hydrogen has about 3 times more volume than methane. However, hydrogen flows much faster through gas grids. The net effect of both elements is that transport of hydrogen requires at least 20% more pipeline capacity per unit of energy compared to natural gas.

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 reinvestment projects. A general political recognition of the existing gas infrastructure to efficiently decarbonise a part of the European economy is advisable.

Most biomethane is transported and distributed through existing gas infrastructure

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 as included in Appendix 1 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 Pathway we assume that 75 bcm biomethane plus an additional 14 bcm of power to methane could be injected into gas grids by 2050.

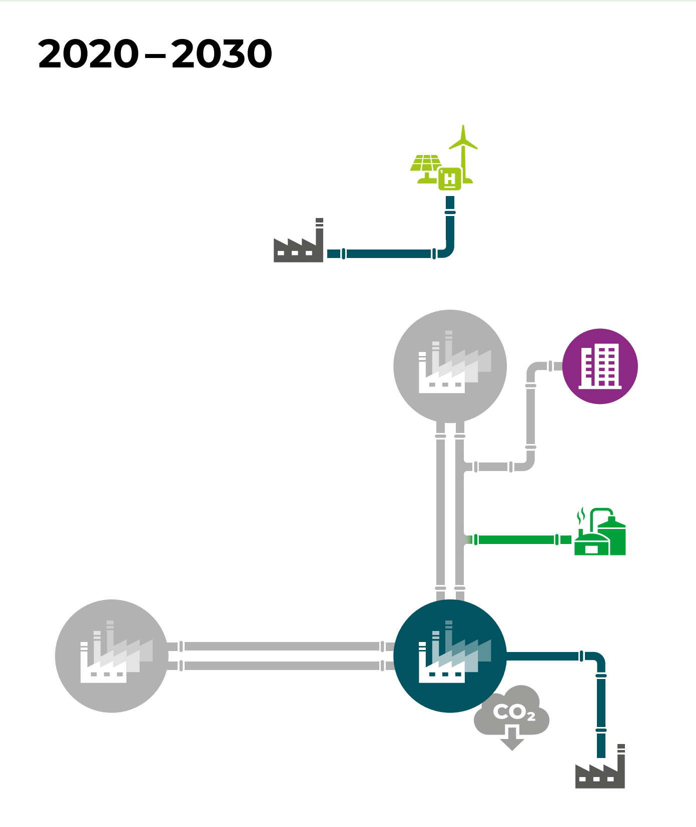
Gradual phaseout of natural gas means the gas grid is split between hydrogen and methane.

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 for hydrogen transport 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 an energy unit of hydrogen requires 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 illustrates the main gas grid developments during 2020 and 2050.

Figure 22.

Development of gas infrastructure from 2020 to 2050 (illustrative)



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

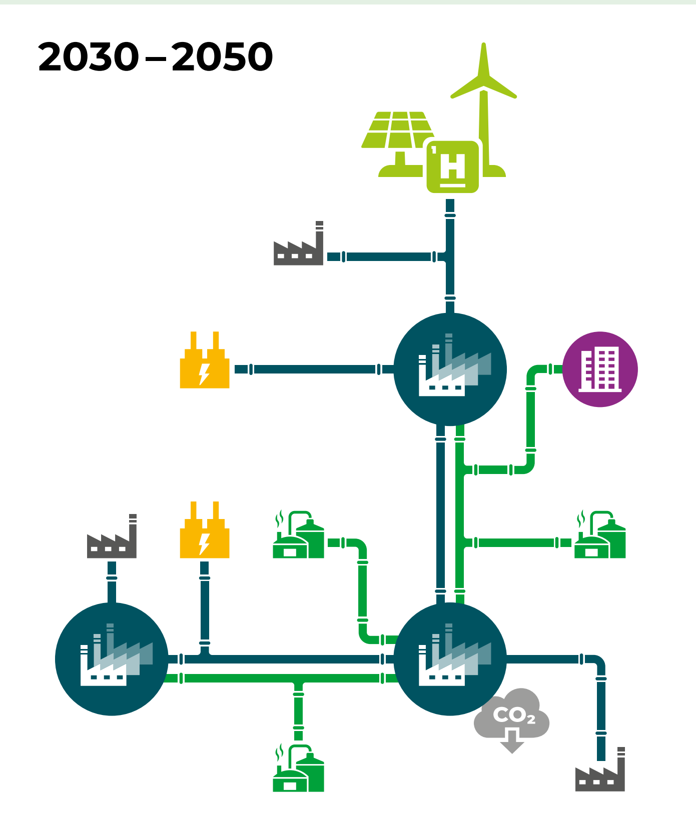
Industry cluster using natural gas

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

3. How do current EU policies help to decarbonise EU gas supply?

Key takeaways

- → Current EU climate and energy policies and NECPs do not provide structural drivers at the EU level for a fully integrated energy system, the increase of biomethane and green hydrogen supply to gas grids or their subsequent use in the relevant sectors.
- → Private investments in renewable and low carbon gases and gas infrastructure require long-term certainty and sufficient incentives to energy using sectors, investors, and project developers. Current EU policies fall short in providing such a framework, even though the Innovation Fund and the increasing EU ETS price can make a difference.

Chapter 2 mapped out the potential and the value of renewable gas and gas infrastructure for a fully integrated energy system in Europe. The next step is to scale-up renewable and low carbon gas. In the European Union, biomethane as well as green and blue hydrogen production needs to scale-up rapidly and massively to minimise cumulative CO_2 emissions and to cost-effectively achieve a net-zero carbon energy system by 2050. This requires many different stakeholders to act. The Gas for Climate consortium is committed to supporting decarbonisation by facilitating an effective sector coupling that integrates the electricity and gas markets and their relevant infrastructures in the best possible way. Furthermore, Gas for Climate is committed to the scale-up of production of renewable and low carbon gases and ensuring that the infrastructure is ready to store and transport these in a cost-efficient manner. It also sees a need for improved renewable methane and hydrogen business cases with lower production costs. Consortium members are already acting on this in demonstration projects on green and blue hydrogen, by scaling up biomethane production across Europe and by being active in national stakeholder dialogues (see examples in the Gas for Climate Action Plan[73]).

This chapter analyses how current EU climate and energy policies facilitate the decarbonisation of the EU economy. These policies are largely in place until 2030 and are currently being transposed into national legislation. Member states also NECPs that outlines how member states intend to address energy efficiency, renewables, greenhouse gas emissions reductions, interconnections, and research and innovation.[74] Our Current EU Trends Pathway analyses the expected impact of current 2030 climate and energy policies on the deployment of renewable and low carbon gases and considers the major policies impacting this analysis, which are included below.

- **EU Clean Energy package** (launched in November 2016) was meant to drive development towards an emission reduction of 40%, compared to 1990 levels, by 2030. The targets for energy efficiency and renewable energy were revised upwards in 2018, effectively raising the resulting 2030 greenhouse gas reduction to 45.6% compared to 1990 levels.
- The **new Renewable Energy Directive** (RED II) introduced a legally binding, EU-wide target of 32% renewable energy consumption by 2030. It also includes a 14% sub-target for renewable energy in road transport. The RED II stimulates that member states extend existing Guarantees of Origin schemes to include renewable gases.
- The **EU ETS** is a cornerstone of the EU's policy to combat climate change and is the key tool for reducing greenhouse gases in the industry and power sector. It is the world's first major carbon market and remains the biggest. The system operates in all EU member states plus 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). Under the EU ETS, the price of CO_2 has quadrupled in the past two years from around €5/tonne of CO_2 to about €25/tonne of CO_2 on average in 2019.[75] This increase is mainly caused by postponing the auctioning of allowances (back-loading), the introduction of a market stability reserve, and the overhaul of the EU ETS directive for 2021–2030, which is already resulting 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 the investment decision in breakthrough technologies.

73 Gas for Climate, 2019. Action Plan 2030 (Update 2019): *How can gas help to achieve the Paris Agreement target in an affordable way*. Available at: https://gasforclimate2050.eu/files/files/Gas_for_Climate_Action_Plan_Update_2019.pdf.

74 European Commission, *National energy and climate plans (NECPs)*, https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en

75 SENDECO$_2$, *Precios CO_2*, https://www.sendeco2.com/es/precios-co2; Sandbag, *Carbon Price Viewer*, https://sandbag.org.uk/carbon-price-viewer/.

→ The EU ETS also provides revenue to the world's largest funding programmes for demonstration of innovative low carbon technologies—the **EU Innovation Fund**. The Fund may amount to about €10 billion until 2030, depending on the carbon price, to support innovation for energy-intensive industry, renewables, energy storage, and CCS/CCU. The Innovation Fund focusses on the demonstration of the next generation of low carbon technologies and processes needed for the EU low carbon transition.

This study concludes that existing EU climate and energy policies, even when fully implemented by member states, and NECPs are insufficient to achieve a meaningful deployment of renewable and low carbon gas by 2030 and 2050. This scenario is not business as usual since not all EU policies and targets have been transposed into national policies; with current developments, the EU 2030 targets will probably not be reached, and reaching the 2050 target will become highly unrealistic.

Existing EU climate and energy policies are insufficient to achieve a meaningful deployment of renewable and low carbon gas

The sections that follow describe the extent to which current EU climate and energy policies can expect to foster the deployment of renewable and low carbon gases including their uses in key parts of the energy system.

Biomethane scale-up under current EU policies

The EU policies that affect the uptake of biomethane are the RED, the Gas Directive, the Innovation Fund, and CEN standards. The RED specifies the way in which biomethane can be counted against the 14% target for renewables in road transport and specifies that biomethane used to produce power and heat can count towards the overall 32% renewables target. The Gas Directive specifies that biomethane is treated in the same way as natural gas when it comes to the EU market regulation. The Innovation Fund could provide funding for innovative, industrial scale biomass-to-biomethane gasification plants. In 2016, the European Standard setting body CEN published two standards, one on natural gas and biomethane for use in transport and another on biomethane for injection in the natural gas network. CEN is currently working to improve parts of these standards.

France uses the transposition of the RED to introduce a binding mandate for 10% biomethane in the French gas grid by 2030. Italy introduced a biomethane subsidy scheme that supports the production of 1 bcm of biomethane destined to the transport sector by 2022.

These existing policies lead to a visible increase in EU biomethane production. In France, a new biomethane facility was opened every week during 2019. Italy will see a large increase in coming years as well. Denmark has financed the building of several dozens of large biomethane plants with a production of well over 1,000 m^3/hr each, going up to 2,000 m^3/hr. Such installations are about seven times larger than the current EU average and they source their biomass and distribute digestate back to the fields within a range of 25 km. In addition to such newly installed installations, expanding biomethane by adding methanation units to already existing biogas plants represents an easy opportunity through 2030. Today, about 16 bcm of biogas is produced in Europe that does not make it to gas grids and is mainly used to produce baseload electricity, which is nonflexible and expensive to store electricity. For example, a project is in development in Bitburg to upgrade existing biogas production to biomethane. For this project, seven existing biogas plants, both small and big, are connected with a biogas pipeline that transports biogas to a centralised biomethane plant close to the gas grid.[76]

76 See: https://www.kne-web.de/verbundsystem/zukuenftige_produkte/

Gas control lines at a compressor station of ONTRAS in Bobbau (Saxony-Anhalt).

← Gas drying facility at a compressor station of ONTRAS in Bobbau (Saxony-Anhalt).

Enagás compressor station in Sevilla, Spain. ↓

Despite these developments, it is unlikely that current EU policies will deliver 95 bcm of biomethane by 2050. It may be possible to upgrade about 10 or 12 bcm of already existing biogas production to biomethane by 2030, and new biomethane plants will be built in countries such as France, Italy, Denmark. However, Denmark has recently frozen its biomethane incentive scheme and Europe's largest biogas producing country, Germany, does not anticipate financing new biogas capacity in coming years.

The scale-up of biomethane gasification is hampered by the very large investment per individual installation and the high project risk, which can only be mitigated if a long-term outlook for a stable business case exists. Successful first-of-a-kind commercial projects would have a size of at least 100 MW at an investment cost of perhaps €350 million[77] and would be developed in large gas markets with stable support policies for biomethane.

The previous NER300 EU subsidy scheme failed to generate investments in large-scale (bioenergy) projects.[78] The Innovation Fund as its successor is designed to incorporate lessons from these experiences. For example, by providing not just CAPEX but also OPEX funding, by providing funding during the development and construction phase rather than only once a project becomes operational. Furthermore, the Innovation Fund assists in project development and stimulates innovative first of a kind project on European territory.[79] Therefore it can be expected that the Innovation Fund may be able successfully co-finance a first of a kind commercial scale biomass to biomethane gasification facility in an EU Member State that provides a favourable longer term perspective for biomethane. Yet although we can expect the Innovation Fund to help finance several initial large gasification plants, even if 10 of these plants are built by 2030, this would still only result in 1.3 bcm of biomethane. The Innovation Fund will not be able to finance the large-scale roll-out of gasification plants beyond the initial few large projects. Such scale-up (the 2019 Gas for Climate study assumes 228 large 200 MW gasification plants by 2050) will only be feasible under a long-term policy framework that offers the right incentive for biomethane gasification while pushing for continuous cost reductions in order to minimise societal costs. This is further discussed in the next chapter.

Hydrogen scale-up under current EU policies

Under the EU's current policies, it is likely that part of existing steam methane reforming and autothermal reforming plants will be retrofitted with CCS by 2040, amounting to a supply of around 100 TWh blue hydrogen. Support mechanisms like the Innovation Fund are expected to fund projects, retrofitting conventional hydrogen units in refineries and in industrial gas producers. The development of blue hydrogen will stagnate after 2040 because it is viewed by society and politicians as a bridge-option that is useful during the energy transition yet should be phased out towards 2050. This limits the deployment of greenfield blue hydrogen assets. Apart from the Netherlands, Belgium, and France, support mechanisms and concrete targets for the supply of green hydrogen are largely absent in the EU. The upcoming German national hydrogen strategy may include dedicated support for hydrogen as well. Announced plans for electrolysis in the EU will increase supply to around 4 TWh (2 GW) of green hydrogen by 2030, with the European Commission expecting around 35 TWh (18 GW) in its 2050 baseline scenario. Based on existing policy, we expect that, in the short- and long-term, low carbon hydrogen production will remain limited in the EU with natural gas as the dominant feedstock.

77 Based on Thunman et al, *Economic assessment of advanced biofuel production via gasification using real cost data from GoBiGas, a first-of-its-kind industrial installation*, published in Energy Science & Engeneering (2019), see: https://onlinelibrary.wiley.com/doi/full/10.1002/ese3.271

78 Max Åhman et al, *Demonstrating climate mitigation technologies: An early assessment of the NER 300 programme*, Energy Policy volume 117 (June 2018), p. 100-107. See: https://www.sciencedirect.com/science/article/pii/S0301421518301095

79 https://ec.europa.eu/clima/sites/clima/files/innovation-fund/innovation_fund_factsheet_en.pdf

Current EU policies do not deliver effective decarbonisation of buildings

The Energy Performance for Buildings Directive (EPBD)[80] is the central policy in place to guide the EU energy transition in the buildings sector. The EPDB includes certification (or energy labels) for energy performance for buildings including minimum energy performance requirements for replacing or retrofitting building elements and the requirement of long-term renovation roadmaps for member states. In addition, the development of renovation targets for public buildings 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 also 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.

Under the Current EU Trends Pathway, we expect buildings to have light renovation efforts in line with the current situation (renovation rates between 1% and 1.5% of mostly light and medium renovations). However, there will be a limited share of deep renovations towards 2030. This will result in a relatively low reduction of heat demand and a relatively low application of hybrid heat pumps. Increasing the renovation speed and depth after 2030 to compensate for the lacking renovations between 2030 and 2050 will be a near impossible task. Based on data from Heat Roadmap EU[82] 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 natural gas seems unlikely in this scenario due to the relatively limited share of energy reduction in the built environment.

EU ETS gradually becomes more effective, yet additional action is needed to decarbonise industry

The EU ETS is the main policy driver for decarbonising the industry sector. Under the EU ETS, the price of CO_2 has quadrupled between 2017 and 2019 from around €5/tonne of CO_2 to more than €20/tonne of CO_2.[83] This increase is mainly

ETS price increases, yet not fast enough for industry to invest in deep decarbonisation

caused by the overhaul of the EU ETS directive for the years 2020-2030. Higher CO_2 prices increase the production costs for the energy-intensive industry and consequently the investment decision in breakthrough technologies. In the Current EU Trends Pathway, we assume a moderate price increase reaching €35/tonnes of CO_2 in 2030.[84] Other EU policies that substantially impact the industry sector include the 2017 industry strategy and the 2015 action plan on circular economy.

Under current EU policies, there will be limited investments in breakthrough technologies in the coming decade. Technology developments in the industry sectors are driven by efforts to reduce costs and improve the quality of the final output. Energy

80 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.
81 While originated in the EED, the LTRS have been moved to the EPBD in the 2018 update of the EPBD.
82 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.
83 Sandbag, *Carbon Price Viewer*, https://sandbag.org.uk/carbon-price-viewer/.
84 This is broadly in line with what IEA finds for the EU in its Stated Policies scenario (CO_2 price $33 per tonne, in $2018); IEA< *World Energy Outlook 2019*: https://www.iea.org/reports/world-energy-outlook-2019

costs and regulatory costs (e.g. CO_2 prices) make up a substantial portion of total production costs. Primary energy consumption and greenhouse gas emissions have been gradually declining since the 1990s, but substantial emission reductions in the industry are difficult to realise with energy efficiency measures given the large share of process emissions. Due to natural replacement cycles, large investments in the chemical, steel, and cement industry are needed 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), which leaves the industry with three options: postponing investments into the 2030s, investing in conventional technologies, or investing in new technologies outside of Europe. Regulatory uncertainty negatively impacts long-term planning security.

As a result, the demand in renewable and low carbon gases in the energy-intensive industry in 2030 will only be around 25 TWh-35 TWh. 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. In the cement sector, only few sites will apply CCS/CCU. The remaining industry will focus on improving energy efficiency to reduce 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 of 696 TWh of renewable gas is unlikely to be reached. Instead, demand will be around 250 TWh–300 TWh in 2050, with 400 TWh–450 TWh of natural gas use.

Current policies can largely electrify light road transport, heavy transport requires more action

A diverse set of policies impact the transport sector. In general, EU policies on road transport 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). Most of the EU international shipping sector's ambitions were moved ahead via the International Maritime Organisation (IMO).[85] IMO's strategy is to reduce CO_2 emissions by at least 40% in 2030 and it pursues efforts to reduce emissions by 70% by 2050 compared to 2008.[86] The International Civil Aviation Organisation (ICAO)[87] 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."[88] 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.

Current policies drive electrification of light road transport, not the decarbonisation of heavy transport

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.

85 Transport & Environment, *EU shipping's climate record, Maritime CO_2 emissions and real-world ship efficiency performance*, 2019.
86 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.
87 European Commission, https://ec.europa.eu/clima/policies/transport/aviation_en.
88 International Air Transport Association, *Carbon offsetting for international aviation*, 2019, https://www.iata.org/policy/environment/Documents/paper-offsetting-for-aviation.pdf.

BEVs will penetrate the light vehicle market under current policies. BloombergNEF predicts sales levels of 65% BEV passenger cars in 2040 based on current trends; however, these sales would not be enough to create a completely decarbonised passenger car sector in 2050.[89] 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 adoption rates to remain less than 1% for passenger cars and less than 5% for buses and trucks in 2050, largely because of the lack of cost reductions in fuel cell technologies.[90]

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.

In aviation, CO_2 emissions will be reduced up to around 10% through the blending of biokerosene in 2050 (95 TWh).[91] There will be no role (or a limited role) for synthetic kerosene in this scenario due to high costs for the production of green hydrogen, and the limited role of greenfield blue hydrogen plants to supply new demand. Support schemes for synthetic fuels are also absent. In shipping, fleets will continue to shift to using (bio)-LNG when it becomes available in locations at enough volumes. However, in this scenario, due to the long lifetimes a partial switch to (bio)-LNG can be expected at best, fossil ship fuel oils likely will remain the dominant fuel type.

Europe's electricity sector rapidly goes renewable, yet more is possible

RED and EU ETS are the main policy drivers for decarbonising the power sector. The revised RED (RED II) established a new binding renewable energy target of at least 32% for 2030. The EU ETS established price levels of €20/tonne CO_2 in 2019,[92] increased the development of renewable and low carbon electricity generation and promoted a shift from coal-based towards natural gas-based electricity generation.

Renewable electricity can scale-up even more than the current predicted 55% by 2030

Under the Current EU Trends Pathway, renewable electricity shares increase towards 55% by 2030. We expect electricity demand to be stable towards 2030 because of limited electrification efforts and ongoing efficiency improvements that offset the additional demand. When renewable electricity shares 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 climate and energy policies do not provide structural drivers at the EU level for the increase of biomethane and green hydrogen supply to gas grids. By 2030, production of green hydrogen would be restricted to pilot plants since almost all

89 Bloomberg NEF, *Electric vehicle outlook 2019*, 2019
90 Fuel cell and Hydrogen Joint Undertaking, *Hydrogen roadmap Europe*, 2019, https://www.FCEV.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf
91 Transport & Environment, *Roadmap to decarbonising European aviation*, 2018
92 Carbon Price Viewer, *EUA Price*, Sandbag: *Smarter Climate Policy*, https://sandbag.org.uk/carbon-price-viewer/.

renewable electricity can still be delivered to the electricity grid directly. The expected CO_2 price in 2030 (around €35/tCO_2) is not sufficient to introduce blue hydrogen as a large-scale replacement of grey hydrogen (hydrogen produced without CCS), which requires a CO_2 price of around €50/tCO_2. Nor will there be enough incentives to accelerate the development and scale-up of green hydrogen techniques. As a result, the Current EU Trends Pathway shows that developments in the 2020s will occur too slowly to enable a scale-up of renewable and low carbon gas in line with the Gas for Climate 2050 Optimised Gas end state.

Current EU climate and energy policies result in insufficient acceleration of energy renovations in homes and other buildings and they give heavy industry too little long-term certainty to grasp the conversion opportunities emerging in the 2020s to move towards full decarbonisation. In transport, current policies do not deliver enough momentum in decarbonising heavy road transport, shipping, and aviation. Renewable electricity reaches a share of around 55% in 2030, but the share of variable wind and solar PV will still only be around 35%, which does not provide a driver for the development of decarbonised dispatchable power via low carbon gases. The remaining 20% comes from dispatchable hydropower plants and bio-based power plants.

Private investments in renewable and low carbon gases can only be scaled up within a political and regulatory framework that provides long-term certainty and enough incentives to energy-intensive sectors, investors, and project developers. Even though the Innovation Fund is already an important driver of renewable gas demonstration and commercial projects, and while the increasing EU ETS price improves the business case for large-scale biomethane and blue and green hydrogen, the current EU climate and energy policies fall short in providing such framework.

Gas infrastructure mainly used for natural gas, yet becoming more diverse

Gas infrastructure plays an important role in the EU energy system. However, this role is not sufficiently reflected in the long-term strategy of the EU Energy Union. At present, the EU Energy Union strategy aims to remove technical and regulatory barriers to energy flowing freely throughout the EU. The Energy Union also stimulates international collaboration in the Energy Infrastructure Forum and in high level groups. Development of the infrastructure is facilitated via the Trans-European Networks for Energy and Projects of Common Interest.[93] Under current EU policies, by 2030 and 2050, gas infrastructure will mainly be used to transport natural gas in gradually decreasing amounts. Current policies do not explicitly stimulate the development of large international hydrogen pipelines or backbones, nor do they support (preparations for) retrofitting existing transport pipelines. The existing international hydrogen connections were developed and are owned by integrated hydrogen production and sales companies that produce hydrogen and supply it to industrial clusters in Northern France, Belgium, and the Netherlands. However, they have insufficient capacity to support a massive scale-up and cost decrease of hydrogen technologies to date. An effective mechanism in the long-term strategy of the EU Energy Union is crucial to ensure the most efficient use of the gas infrastructure in the energy transition.

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

4.
Gas for Climate proposals for the EU Green Deal

Key takeaways

→ Binding 2030 mandate for gas from renewable sources would help to scale-up supply of bio-methane and green hydrogen.

→ The trade and transport of biomethane, green hydrogen, and blue hydrogen needs to be improved and the market rules for hydrogen and its transportation are to be clarified.

→ In parallel, the EU ETS must be strengthened and broadened to ensure accelerated decarbonisation in energy demand sectors, plus temporary additional support is needed to ensure that heavy industry chooses deep decarbonisation in natural reinvestment moments during the 2020s.

→ The European gas infrastructure should be recognised within the regulatory framework as a key asset for the decarbonisation of the European economy providing a sustainable and cost-efficient solution to the transport and storage challenges of a future decarbonised energy system.

→ Planning of energy infrastructure should be more integrated considering the overall energy system and the advantages offered by existing infrastructure.

→ TEN-E and CEF regulations should facilitate and support the integration of renewable gas.

This chapter explores how EU policy can help accelerate the production of biomethane and green and blue hydrogen making the best possible use to the entire energy system of the existing infrastructure. It also identifies where biomethane, green hydrogen, and blue hydrogen use can add the most value in energy demand segments, in a smart combination with increasing levels of renewable electricity.

Becoming the world's first climate-neutral continent requires Europe to implement low carbon technologies now. As analysed in the Gas for Climate's 2019 study, balancing the use of renewable gas and renewable electricity saves society over €200 billion annually by 2050, compared to an energy system that uses a minimal amount of gas. Today, the EU biogas sector represents 71,000 jobs in Europe that are difficult to outsource.[94] The Gas for Climate employment study shows that scaling up renewable gases in the EU can create 1.7 million to 2.4 million jobs by 2050, of which 600,000 to 850,000 would be direct jobs.[95]

Achieving a large-scale deployment of renewable and low carbon gas requires action from many different stakeholders, starting today. Substantial additional climate action is needed by 2030 to reach the Gas for Climate 2050 Optimised Gas end state. The Accelerated Decarbonisation Pathway highlights the actions required of the private sector in the energy, industry, buildings, and transportation sectors to achieve an energy transition that allows Europe to fully decarbonise at the lowest societal costs. The Gas for Climate consortium members all support full decarbonisation and want to ensure that gas infrastructure can transport and store renewable and low carbon gas in the most cost-effective way, largely based on existing gas infrastructure. The Gas for Climate consortium also sees the need to improve renewable methane and hydrogen business cases with lower production costs. Planning of new energy infrastructure should be designed in an integrated way and be based on the overall needs of a future energy system.

Much more is possible by 2030 as part of an EU Green Deal under the Accelerated Decarbonisation Pathway

The section below describes the main bottlenecks to scaling-up hydrogen and biomethane and discusses how policy can help overcome them.

The main bottlenecks that prevent investments in blue hydrogen in the 2020s are:

- Insufficiently high CO_2 prices; no outlook on the roughly €50/tCO_2 that could build the business case.
- CO_2 storage is not currently permitted in many EU member states, as not all policymakers and stakeholders support CCS as an instrument to mitigate climate change.
- Ambiguity exists on whether TSOs can transport CO_2 for storage in offshore formations, both domestically and internationally.[96] In the Netherlands, Norway and the UK, authorities have provided regulatory certainty on this, the same should be arranged EU-wide.
- No clarity on liabilities around CO_2 storage.

94 IRENA, 2018. *Renewable energy and jobs – Annual review 2018*. Available at: https://www.irena.org/publications/2018/May/Renewable-Energy-and-Jobs-Annual-Review-2018; EurObserv'ER (2018). The state of renewable energies in Europe edition 2018 - 18th Eu8 EurObserv'ER (2018).

95 Navigant, 2019. *Gas for Climate. Job creation by scaling up renewable gas in Europe*. Available at: https://gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_Job_creation_by_scaling_up_renewable_gas_in_Europe.pdf

96 Article 6 of the London Protocol, a treaty under the International Maritime Organization (IMO), implicitly prohibits the cross-boundary transport of CO_2 prior to sequestration under the seabed as this would classify as "waste dumping or incineration at sea". An amendment to this treaty was already written in 2009, but only six countries had ratified so far, failing to reach the two-third majority needed to pass. As a temporary solution, Norway and the Netherlands developed a proposal asking for the amendment to be implemented for those countries who had ratified it and was approved in October 2019. This means that currently Norway, the United Kingdom, the Netherlands, Iran, Finland and Estonia can exchange CO_2 amongst each other for CCS projects. Source: NCLOS (2019), *Provisional Application of an Amendment to the London Protocol to Facilitate Collaborative CCS Projects*. https://site.uit.no/nclos/2019/12/11/provisional-application-of-an-amendment-to-the-london-protocol-to-facilitate-collaborative-ccs-projects/x

Solutions could be found in:

- Strengthening the EU ETS leading to at least €55/tCO_2 by 2030 plus dedicated and time-bound national subsidies, like Contracts for Difference (CfD), to kickstart blue hydrogen production during the 2020s.
- Investors focusing on member states where CO_2 storage is currently allowed, while policymakers work on spreading that to more member states.
- The political debate, which should detail the conditions under which CCS could be a more widely accepted instrument to mitigate climate change.
    - For example, a condition could be that any CCS project must have a phaseout clause by 2050 unless it is used to generate negative emissions afterwards, i.e. by producing climate positive hydrogen. Using CCS as a tool to create negative emissions can help to create longer-term support for the technology.
- The EU and national regulators providing clarity for gas TSOs on being allowed to transport CO_2 and provide best practices on how long-term liabilities could be clarified so energy companies and investors will have confidence to invest in CCS.

The main bottlenecks that prevent investments in **green hydrogen** during the 2020s are:

- High costs. While the cost of green hydrogen is declining rapidly, it is still prohibitively expensive today and current production units are too small.
- For large-scale application during the 2020s, there is:
    - Insufficient wind and solar generation capacity beyond what is needed to serve direct electricity demand
    - No clarity on whether gas TSOs are allowed to transport hydrogen
    - Hydrogen used for energy storage can face double taxation on the basis of electricity used as input when hydrogen is stored[97]

Solutions could be found in:

- The EU Innovation Fund to co-fund initial large electrolyser projects during the 2020s.
- Longer-term investor certainty and positive business case provided by a mandatory target for gas from renewable sources in 2030.
- Production costs to decrease through economies of scale and learning effects, subsidy regimes can be designed to accelerate this.
- Double taxation on electrolysers to be removed, requiring a modification of the Energy Tax Directive.
- Certificate-trading of hydrogen should become possible both within EU Member States and across borders. This requires a set of harmonised rules on defining green hydrogen and setting up certificate-schemes. The voluntary development of CertifHy[98] is a positive initiative.
- TSOs should be allowed to invest in dedicated hydrogen pipelines and should be allowed to blend a limited amount of hydrogen in natural gas.

The main bottlenecks that prevent investments in **biomethane** during the 2020s are:

- High production costs compared to natural gas plus the current CO_2 price
- An increased EU ETS price of €55/tCO_2 by 2030 is likely to be insufficient to create a positive business case for biomethane using in industry and power production.
- Limited political and societal support for a long-term valuable role for biomethane to decarbonise the energy system.
- Limited possibilities for cross-border trade of biomethane.
- High investment costs for biomethane gasification projects, which must be large-scale to be economically viable (see Chapter 3).

Solutions could be found in:

- A further increase of the ETS price beyond 2030 from €55/tCO_2 to €100/tCO_2 by and €150/tCO_2 by 2040 and €150 by 2050 would help to bridge the gap. For the 2020s and 2030s additional incentives are needed.

97 The European Commission writes in SWD(2019)329 (2019), *Commission staff working, evaluation of the Energy Tax Directive*, p.36: 'The ETD states that electricity is taxed when released for consumption but does not define whether electricity is released for consumption when supplied to storage facilities. This opens the possibility of double taxation of electricity that is stored and re-sold.' See: https://ec.europa.eu/taxation_customs/sites/taxation/files/energy-tax-report-2019.pdf

98 https://www.certifhy.eu/

- EU Member States should (continue to) support biomethane through subsidy regimes up to 2030.
- EU Innovation Fund to co-finance the first large-scale biomethane gasification projects during the 2020s.
- Longer-term investor certainty and positive business case provided by a mandatory target for gas from renewable sources in 2030.
- Production costs to decrease through economies of scale and learning effects. Subsidy regimes can be designed to accelerate this.
- Facilitate the trading to include cross-border trading of biomethane and further harmonise gas quality standards to facilitate blending of biomethane in natural gas.

The analysis above leads to three key recommendations for policy measures to be included in the EU Green Deal. To stimulate an integrated approach on gas and electricity that achieves the goals of the energy transition, it would be necessary to:

1. Stimulate the supply of hydrogen and biomethane by a binding mandate for 10% gas from renewable sources by 2030.
2. Foster cross-border trade and transport of hydrogen and biomethane and clarify market rules for green and blue hydrogen including for hydrogen transport.
3. Incentivise demand for hydrogen and biomethane in EU industry and production of dispatchable electricity by strengthening and broadening the EU Emissions Trading System (ETS) combined with targeted and time-bound Contracts for Difference.
4. Adapt the EU regulatory framework to deploy the gas infrastructure, integrated in the energy system, as a key asset for the sustainable and cost-efficient decarbonisation of the European economy.

Binding mandate of 10% renewable gas by 2030

The RED should be amended to include a binding target of 10% gas from renewable sources by 2030. Such a target would also cover green hydrogen, although it is expected that most of the target would be met by biomethane up to 2030, since in 2030, the green electricity needed for green hydrogen will mostly be needed to decarbonise electricity use in the power sector. Like the renewable fuels target as part of the RED II, EU Member States would obligate national suppliers of gas to ensure the target is met. They can do this by starting to produce renewable gas themselves, by sourcing renewable gas from others, or by purchasing renewable gas certificates to green their supply. Certificates should ensure that for each quantity of renewable gas that counts towards the target somewhere in the EU a corresponding quantity of renewable gas is fed into gas grids, like the certification system currently in place for green electricity. Physical imports of biomethane and green hydrogen should be able to count towards the target, similar to the already existing possibility in the EU RED to count physical imports of renewable electricity towards the target. This provides additional assurance that obligated parties will be able to fulfil the mandate.

Member States could either set a mandatory target for 10% gas from renewable sources for the year 2030 or could introduce binding intermediate targets for the years 2020 to 2030 that provide a pathway towards the 10% target. The first option would provide member states the possibility to continue feed-in subsidy support for biomethane until and including the year 2029. Such support could be targeted towards green hydrogen, biomethane from digestion and biomethane from gasification specifically. The second option could include intermediate sub-targets for various types of renewable gases.

A binding target for renewable gas for 2030, with a clear indication that this target would be continued and increased after 2030, would help to scale up of green hydrogen and biomethane, including from gasification. A binding mandate alone will however be insufficient, especially for biomethane. Equally important is the political messaging on the long-term outlook for bioenergy in the EU energy system. The experience of the EU RED biofuels mandate since 2008, which has been constantly subject to fierce debate shows that investors will shy away from large investments in bioenergy unless unambiguous political support is provided that ‘bioenergy done right’ can, under the right sustainability conditions, be a valuable contribution to the decarbonisation of the EU energy system.

Strengthening the role and effectiveness in deploying climate-neutral innovation of the EU ETS

The EU ETS is the primary instrument for reducing emissions in European energy industries and related industries. The EU ETS aims to control emissions from power generation, district heating (above a certain size, i.e. combustion plants above 20 MW), and several energy-intensive industries. As stated in the European Commission's Green Deal communication in December 2019, the Commission will revise the EU ETS within the Green Deal. Plans include extending the EU ETS to the maritime sector, reducing the EU ETS allowances allocation for free to airlines, and reviewing the role of Innovation and Modernisation Funds.[99]

To reach the required emission reduction within the Accelerated Decarbonisation Pathway, the annual emissions ceiling should be increased from the current 2.2% towards approximately 4% annually.[100] This could translate in a carbon price of €55/tCO_2 by 2030. In the steel sector an ETS price of around €60–€80/tCO_2 already enables investments in breakthrough technologies. This could include investments in ammonia and cement production, and carbon capture can be realised at an even lower carbon price.[101] To switch from steam methane reforming to renewable hydrogen to produce ammonia and from steam cracking to MTO to produce high value chemicals, a carbon price exceeding €150/tCO_2 is required.[102] This means that an additional policy instrument is needed to help decarbonise industry until the moment when the ETS price is sufficiently high. An effective policy instrument can be a programme of targeted and time-bound CfDs. 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 CO_2 abatement costs of a particular technology).

In the steel sector an ETS price of €60-€80/tCO_2 can enable investments in breakthrough technologies

Facilitate the trade and transport of renewable and low carbon gas

Renewable methane and hydrogen need to be transported, stored, and traded. Gas for Climate sees a need for the following improvements:

- Grid access for renewable gas
- Cross-border trade of all forms of renewable and decarbonised gas
- Transport of hydrogen and the coupling and integration of gas and electricity sectors

In addition, political and regulatory support is needed for the creation of a European Hydrogen Backbone infrastructure using where possible existing gas infrastructure. This would help to create a European hydrogen market initially with sources within Europe. This market would trigger additional investments internationally because hydrogen imports would meet security of demand in an existing market.

Cross-border trade should be enabled by the harmonisation of the national registers and setting up an EU-wide connected green gas register that is facilitated by TSOs. An EU-wide, harmonised renewable gas trading platform needs to be set up.

The creation of a cross-EU biomethane certificate scheme would also enable front-running companies with voluntary decarbonisation targets, such as many food and beverage producers that set science-based climate targets, to start sourcing biomethane at a premium price.[103]

Adapt the EU regulatory framework to facilitate a fully integrated energy system and its infrastructures

Clear guidance on gas decarbonisation pathways is needed to reduce uncertainty for investment. Planning of new energy infrastructure should take a holistic view and be based on a future energy

99 European Commission (2019) *The European Green Deal*, retrieved from: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf
100 Carbon Tracker, 2018, *Carbon Clampdown: Closing the Gap to a Paris-compliant EU-ETS*. Available at: https://www.carbontracker.org/reports/carbon-clampdown/.
101 Guidehouse calculation based on confidential industry data.
102 Ibid
103 https://sciencebasedtargets.org/companies-taking-action/

system considering the increasing development of renewable gas and electricity. Infrastructure planning should be more integrated, both between DSO and TSO levels and between the electricity, gas, and heating sectors. As renewable gas and gas infrastructure are becoming a central feature of the future energy system, the focus of existing legislation such as the TEN-E and CEF regulations should shift towards facilitating sector coupling and renewable gas projects.

Next to the four general and most crucial policies described above, we recommend a number of additional policy measures be included in the European Green Deal that specifically target the supply of biomethane and hydrogen as well as their use in buildings, industry, transport, power generation, and infrastructure in the sections that follow (Figure 23).

Figure 23. Additional policy measures to be included in the European Green Deal

1	→ Enable the construction of thousands of biomethane plants
2	→ Develop a solid business case for hydrogen in the next decade
3	→ Make existing gas grids ready for renewable and low carbon gas
4	→ Achieve 100 million hybrid heat pumps in renovated older buildings
5	→ Ensure that EU industry opts for deep decarbonisation investments
6	→ Set the transition towards carbon neutral transport
7	→ Ensure continuous power supply with gas-fired power plants

4.1 Enable the construction of thousands of new biomethane plants

Unlocking the biomethane potential as described in the 2019 Gas for Climate study requires the mobilisation of agricultural and forestry wastes and residues to the extent that they are not required for non-energy uses. It also requires that tens of thousands of farmers (mainly in southern Europe and elsewhere where possible) will need to implement the Biogasdoneright concept to sustainably produce low ILUC risk biogas crops

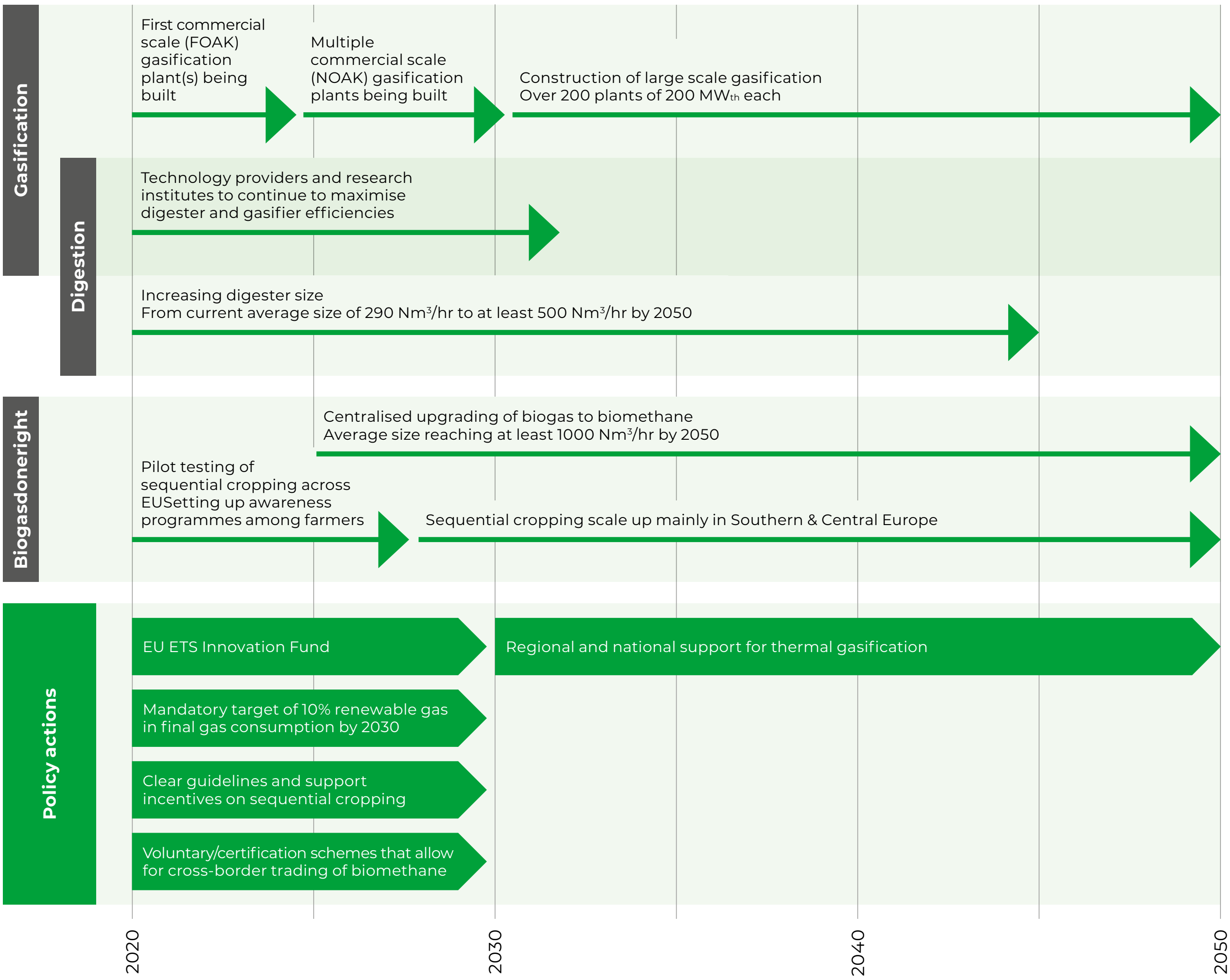
Tens of thousands of European farmers to apply the Biogasdoneright concept of sustainable biomass production

through double cropping. Biogasdoneright has the potential to sustainably increase the availability of biomass for biomethane production. It also helps to minimise soil erosion and has the potential to increase on-farm biodiversity, improve soil health, and increase soil carbon levels. Today, Biogasdoneright has been implemented at some scale in Italy and French farmers have started to apply the concept. To enable a further scale-up, farmers organisations should develop awareness-raising and training programmes among farmers to make them aware of the concept and how to apply it. In parallel, research projects are needed to assess the extent to which the concept can be implemented not just in southern Europe also elsewhere where it proves possible.

Clear guidelines, piloting, and support incentives will be required for sustainable sequential cropping. If sequential cropping does not fully live up to its promise, more green or blue hydrogen would be required to fill in the gaps in renewable and low carbon gas supply.

In addition to a targeted approach to implement Biogasdoneright, a market for tradable biomethane certificates backed by Guarantees of Origin should be organised to provide the possibility for monetising the intrinsic value of biomethane. National legislation combined with a growing market for certificates could establish a meaningful position for biomethane in the EU energy system. Also, the EU Innovation Fund can be used to co-finance large industrial scale biomass-to-biomethane gasification plants.

Figure 24.
Critical timeline and policy actions for biomethane



Source: Guidehouse

4.2 Develop a solid business case for hydrogen in the next decade

With only 339 TWh hydrogen currently produced in the EU and no production of green (except in smaller pilot plants) and blue hydrogen, we are still a long way from the suggested 1,710 TWh in the Gas for Climate 2050 end state. The Accelerated Decarbonisation Pathway as described in section 2.1.2 can lead to the sustainable production of around 200 TWh by 2030 and 2,270 TWh by 2050: 1,710 TWh for the demand in scope of the Gas for Climate report 2019 plus 180 TWh for petrochemicals plus 380 TWh for synthetic fuels. In the coming decade, both blue and green hydrogen projects need to scale-up and improve. All conventional hydrogen assets should be retrofitted with CCS and developing greenfield blue hydrogen capacity should be started, paving the way for future use of green hydrogen. Green hydrogen electrolysis needs to be proven at scale with a total needed capacity of 15 GW-20 GW by 2030. Plants need to improve in efficiency, installation size, and cost, and renewable electricity should become available at very low cost and reasonable full load hours to get the cost of green hydrogen at a competitive level.

The main policies affecting the uptake of hydrogen are the Renewable Energy Directive, the Innovation Fund, and the Fuel Cells and Hydrogen Joint Undertaking programme. Member state policies and strategies such as the Flemish Hydrogen Roadmap (Belgium), the Hydrogen Deployment Plan (France), and the SDE++ and the Climate Agreement (Netherlands) are also impacting hydrogen uptake. However, these are not enough to reach the Accelerated Decarbonisation Pathway.

To increase the uptake of blue hydrogen, public and political attitudes towards CCS need to permit the large scale-up of greenfield blue hydrogen plants. Blue hydrogen is needed as a transitory solution to pave the way for green hydrogen, to reduce cumulative emissions and to help meet 2030 emissions targets by a fast start to emission reductions. Furthermore, the blue hydrogen infrastructure creates an option to achieve much-needed negative emissions by feeding biomethane. This enables (part of) blue hydrogen production assets to continue to be used also after 2050. Strengthening of the EU ETS to achieve a CO_2 price of at least €55/tCO_2 should provide the business case for blue hydrogen projects.

A change in CCS attitudes is required to increase the uptake of blue hydrogen

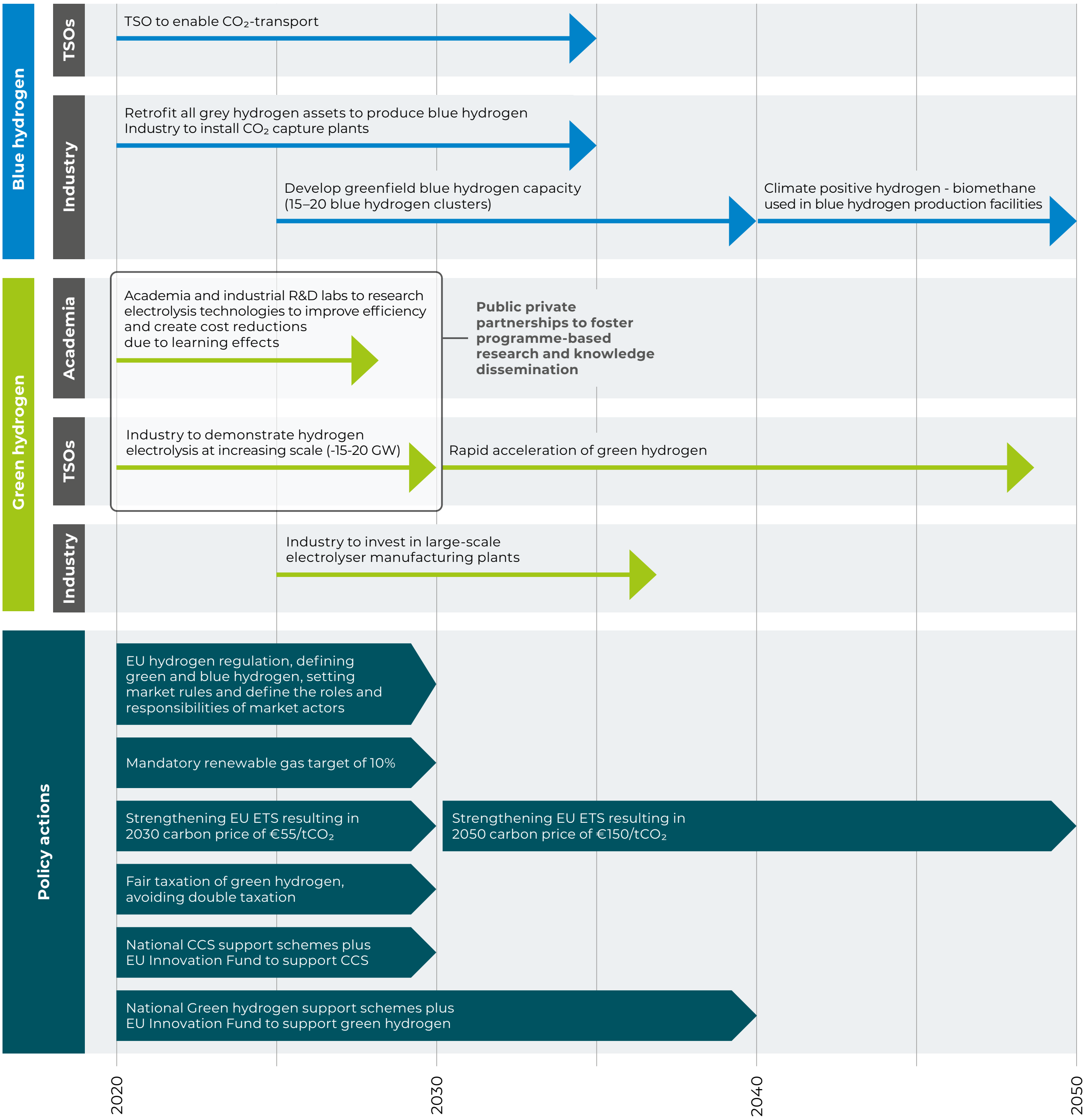
To increase the deployment of green hydrogen in the short term, we need to support significant technology development and associated cost reductions. In current policies, the boundary conditions are not in place to promote the rapid growth of green hydrogen, as the deployment of renewable power sources is limited in the short term and investment costs remain high due to absent policy schemes for green hydrogen.

The recommended 10% binding mandate for renewable gas by 2030 (as described in the previous section) will be instrumental to accelerate the deployment of hydrogen, although due to costs and technology maturity this will mostly be met by the production of biomethane. A strengthening of the EU ETS would also help; however, it will not be enough as green hydrogen requires a CO_2 price of well above €55/tCO_2 today. To improve the green hydrogen business case, policies need to avoid the current double taxation of green hydrogen

Green hydrogen upscale requires significant technology learning and associated cost reductions

in national energy tax laws. Today, the energy tax charges the electricity used to produce hydrogen, while hydrogen as a product is also charged with an energy tax. Large electrolysers are also seen as large demands, with significant grid connection charges having a considerable impact on the business case. Where such electrolysers are used to support the grid, it would be appropriate to reduce the charges. Other green hydrogen support schemes, like CAPEX support for innovative hydrogen production technologies, can further improve the business case and the uptake of hydrogen. This could be implemented within the current EU Innovation Fund or Horizon Europe.

Figure 25.
Critical timeline and policy actions for hydrogen



Source: Guidehouse

4.3 Make existing gas grids ready for renewable and low carbon gas

The current gas infrastructure plays an important role in the EU energy system. During the coming decade, it will continue to be used to transport and store natural gas. For most of Europe, existing gas infrastructure is fit for use and no grid expansion is required (as explained in section 2.4). Also, biomethane can be blended with natural gas without requiring significant gas grid modifications. The large scale-up of hydrogen (as foreseen in the Accelerated Decarbonisation Pathway) requires regional and national hydrogen backbone infrastructures around 2030, which will soon be connected to create a European hydrogen backbone during the 2030s. While the EU Energy Union strategy aims to remove technical and regulatory barriers to energy flowing freely throughout the EU, current policies do not explicitly stimulate the development of large international hydrogen pipelines or backbones.

Investments to create dedicated hydrogen grids are sustainable investments

To be in line with the Accelerated Decarbonisation Pathway, various policies are needed:

1. Connecting biomethane installations to gas grids, investing in reverse flow technology, enabling the uploading of renewable gases to the high pressure grid, the repurposing of parts of gas infrastructure to create dedicated hydrogen infrastructure and investments in new hydrogen infrastructure including hydrogen and CO_2 infrastructure should be classified as sustainable investments under the EU taxonomy rules. National policies should keep flexibility in reusing gas assets by removing potential hurdles for reuse of infrastructure for hydrogen transport.
2. Although several NECPs already foresee a role for hydrogen in 2030, current regulation does not yet facilitate the transport of pure hydrogen in gas infrastructure, similar to the transport of natural gas today.[104] This means that hydrogen transport would be limited to integrated company infrastructure initiatives, mainly focused on captive customers in industries and transport, or through (modest) blending in regulated gas infrastructure. To enable further adoption of hydrogen, as an integral part of the future EU energy system, a regulatory framework for hydrogen needs to be developed, either through an update of the EU Gas Directive or by new legislation. This should allow for investments in hydrogen transport and storage infrastructure, including the retrofitting of existing gas assets, and recouping the cost involved. As for natural gas, a mature and open market for hydrogen requires grids that have third-party access and allow cross-national trading. There should be flexibility in legislation with those parameters to allow for a regime compatible with geography, age, and ownership of the existing grids.
3. Harmonise gas quality standards and standards for biomethane injection in gas grids and set standards and definitions for hydrogen and blended gases to enable their transport through gas infrastructure and across borders. This should consider a current state blend level and variability in blend levels during the year or a ramp up towards the future. Several working groups are examining standards for hydrogen blending (e.g. HyReady and HIPS-Net).[105]

New policy measures must not harm the security of the supply of current gas networks, which are urgently needed for hydrogen or biomethane transport in a future with lots of intermittent electricity. The gradual disruption of security of supply of gas infrastructure by fiscal, financial, or legal measures would remove an essential building block for the future integrated energy system.

104 In Germany, TSOs have proposed to include a green gas scenario focussing on hydrogen transport as part of the Network Development Plan. The regulator has approved such additional perspective – which is unique in Europe as of today – but without any consequences for infrastructure decision to date.
105 IEA, *The future of hydrogen*, 2019

4.4 Apply hybrid heating solutions in 100 million older buildings

In the Accelerated Decarbonisation Pathway, all European buildings will be insulated well in the period 2020 to 2050 and older (pre-2020) 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.

100 million hybrid heat pumps in renovated older buildings are needed to decarbonise the building sector

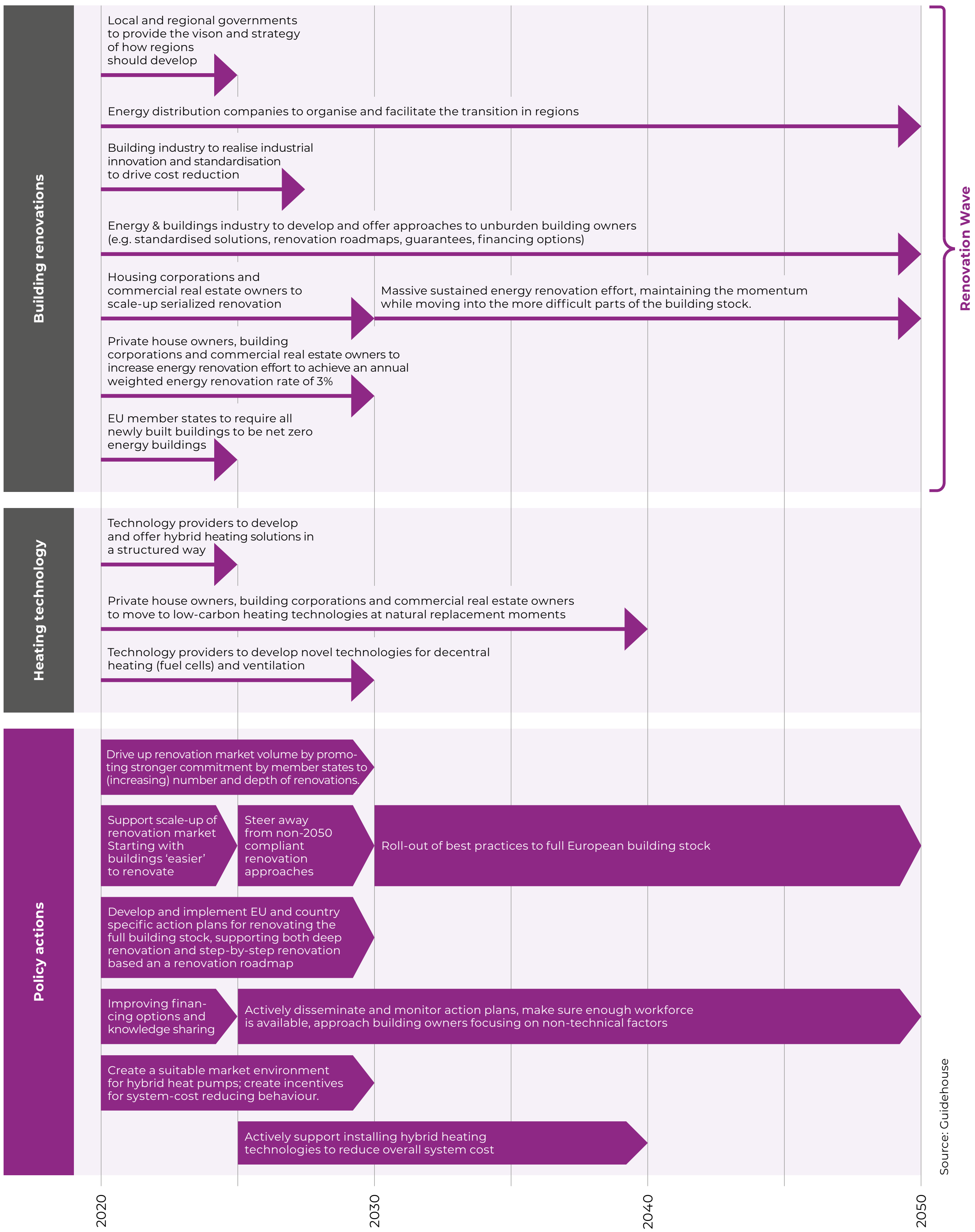
Current EU policies that drive decarbonisation in the EU buildings stock (EPBD, EED, and LTRS) fall short in delivering the necessary renovation speed. Also, limited incentives for hybrid heating solutions exist.[106] In policy studies and scenarios, the option is often overlooked: by 2050, buildings 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 European Green Deal:

1. Kick off the announced Renovation Wave by setting 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. This will accelerate the improvement of buildings' energy performance.
2. Take up the option of hybrid heating systems in policy studies, scenarios, and in plans for the 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
5. Actively propagate the installation of hybrid heat pumps in older buildings that have gas connections today.

106 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 26.
Critical timeline and policy actions for buildings



Source: Guidehouse

4.5 Ensure that EU industry opts for deep decarbonisation investments

Efforts are needed to avoid industry relocation outside the EU as the European industry faces international competition. Without protective measures, increased energy and regulatory costs can be a competitive disadvantage. To maintain integrated value chains from basic materials (e.g. steel, chemicals, cement) to finished products (e.g. cars, electronics) measures such as carbon border adjustments need to be put in place to compensate for the costs ensuing from EU policies.

As explained in section 2.2.2, further decarbonisation of the industry is a challenge, particularly for feedstocks and high temperature processes. The Gas for Climate Optimised Gas end state requires major changes. In the steel sector, the current blast furnace process for primary steelmaking must 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. The cement industry should reduce its process emissions by applying carbon capture and reduce its energy-related emissions by switching from fossil fuels to solid biomass.

While in the chemical sector the ammonia production process will stay largely unchanged using renewable hydrogen as feedstock instead of grey hydrogen, the production of high value chemicals (HVC) should shift from steam cracking to the MTO route.

Almost all steel plants in Europe began production between 1960 to 1980 and will reach the end of their lifetime in the coming 5 to15 years. In that timeframe, steel companies will have to decide whether to invest in the modernisation of existing plants, which constitutes a significant financial commitment given the age of the plants, or in breakthrough technologies. The situation is similar in the chemical industry. Most installations

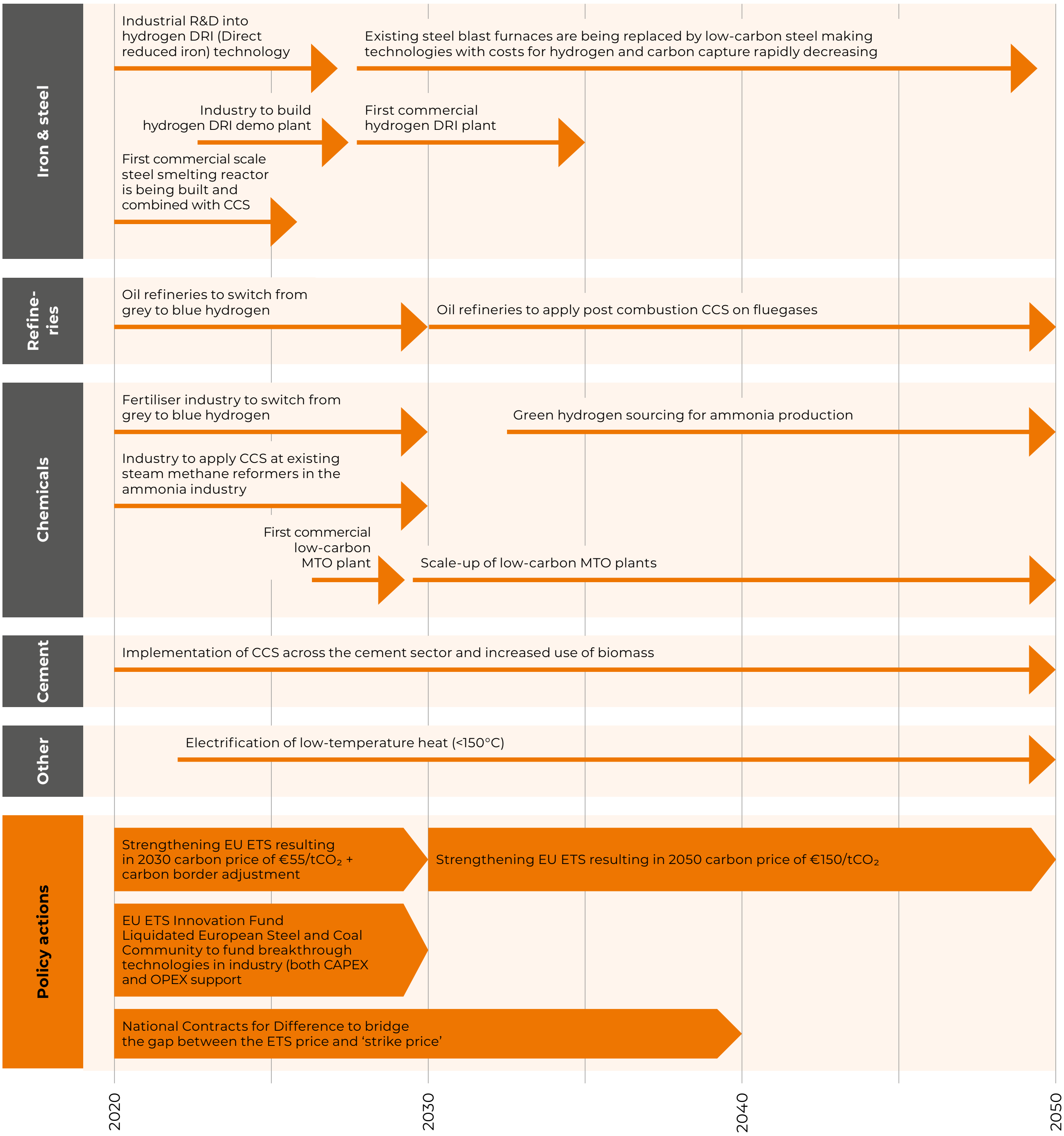
Almost the entire cement and steel industry will have natural re-investment moments during the next 5-15 years

are 30 years or older and will require substantial reinvestments in the next two decades. It is time to opt for deep decarbonisation investments. However, this requires clear incentives.

The EU ETS is the primary instrument for reducing emissions in industry. Strengthening the EU ETS carbon price in a stable wa should provide long-term planning security for an industry that considers long investment cycles. The ETS price for industry depends per sector; for the steel sector, an ETS price of €60-€80/tCO_2 could enable investments in breakthrough technologies. In ammonia and in cement production, carbon capture can be realised at an even lower carbon price. On the other hand, to switch from steam methane reforming to renewable hydrogen to produce ammonia, and from steam cracking to MTO to produce high value chemicals, a carbon price exceeding €150/tCO_2 is required.[107] This means that additional policy instruments can help to decarbonise industry at a lower ETS price. One effective measure can be a targeted and time-bound Contract for Difference (CfD) scheme, as explained at the start of this Chapter. This could bridge the gap between the CO_2 price trajectory and what is required to invest while the CO_2 price is still insufficient. In addition, there will be a role for the Innovation Fund to support breakthrough technologies in industry. The establishment of a hydrogen infrastructure to industrial clusters will enable the uptake of hydrogen.

107 Guidehouse calculation based on confidential industry data.

Figure 27.
Critical timeline and policy actions for industry



Source: Guidehouse

Today, direct reduction of iron ore would be around 50% more expensive compared to conventional primary steelmaking in a blast furnace but it will become cost-competitive with decreasing hydrogen prices.

Investment costs are substantial ranging from €300 to €600 million for a typical steel installation (annual capacity of 4,000 kt). Production costs for primary steelmaking are around €350–€400/tonne of pig iron, 10% of which can be allocated to capital expenditure (CAPEX). However, energy costs make up between 25% (conventional steelmaking) and 40% (direct reduction of iron ore with hydrogen) of total production costs. Hence, low carbon steel produced via hydrogen is now still significantly more expensive. Given decreasing hydrogen costs and increasing CO_2 prices, low carbon steelmaking will become cost-competitive in the mid-term.

4.6 Set the transition towards carbon neutral transport

As explained in Chapter 3, 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 2.2.3.

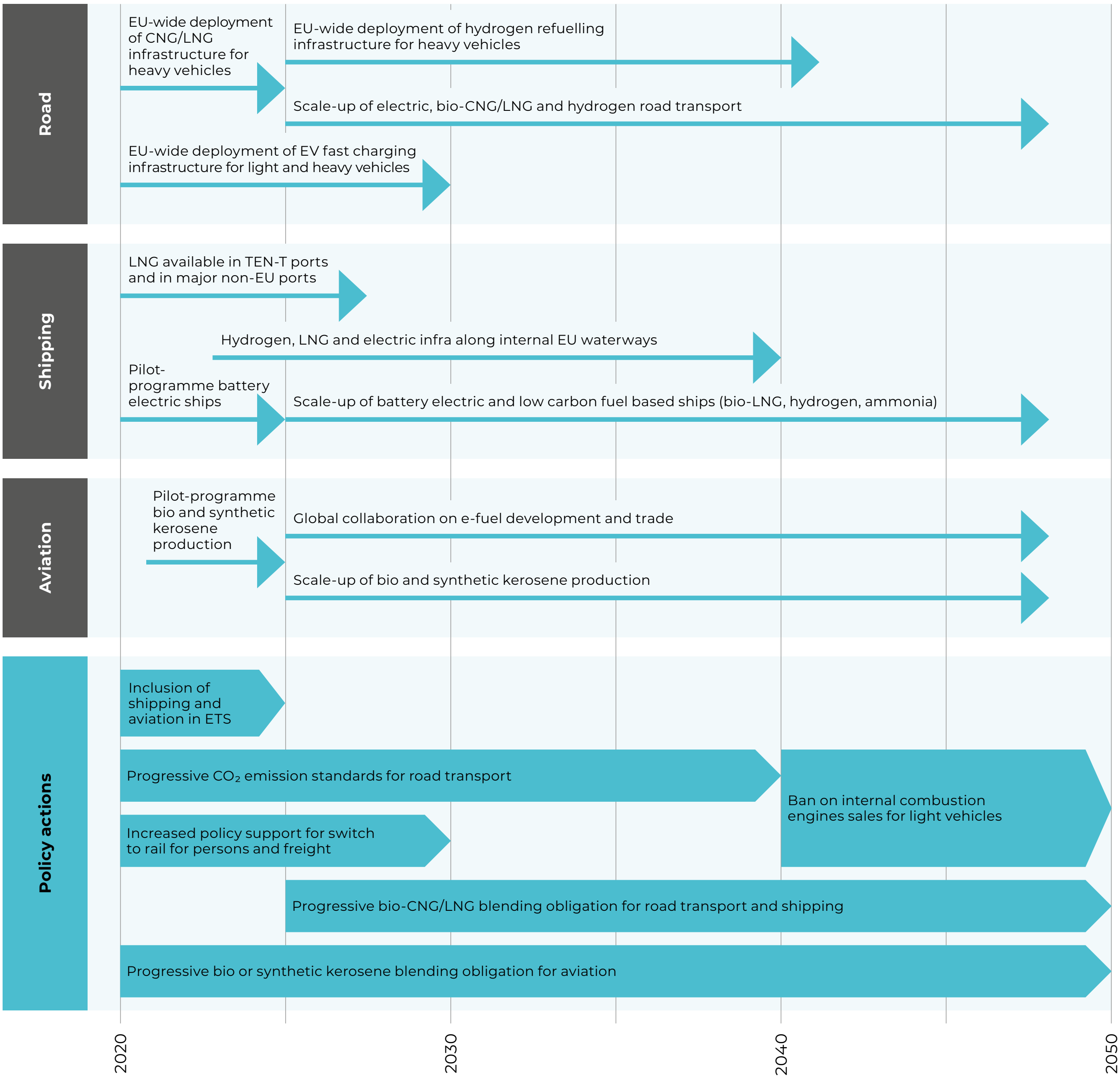
There is a diverse set of policies impacting the transport sector. In general, EU's road transport policies are mainly built on two pillars: improvement of engine efficiencies (regulation of CO_2 emissions in vehicles) and decarbonisation of the fuel mix (RED I and II).

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.

Figure 28.
Critical timeline and policy actions for transport



Source: Guidehouse

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.

4.7 Ensure continuous power supply with gas-fired power plants

Electrifying the energy system is essential to achieving a net-zero emissions EU energy system. As explained in section 2.3, 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 backup 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.

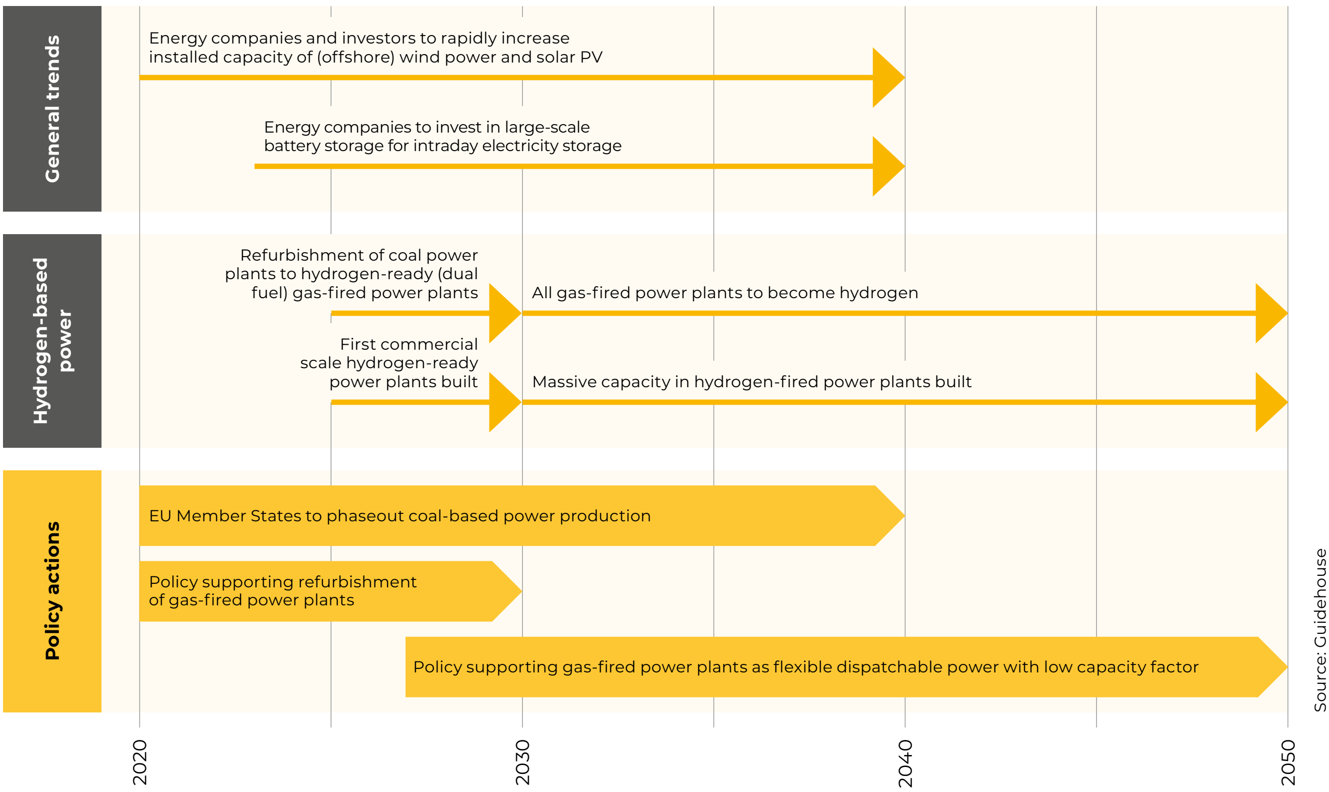
In 2030 60%–70% of the electricity generation will come from renewable sources

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 backup.

Figure 29.
Critical timeline and policy actions for power



5.
What if the future develops differently: Alternatives to the central pathway

Key takeaways

- Reaching a net-zero emissions energy system by 2050 requires action across many levels. If developments stagnate in specific sectors, this places additional pressure on alternative technologies, different sectors, and the need to source renewable energy from outside Europe.
- However, if countries around the world begin to work towards meeting the Paris Agreement goals, shares of renewable energy will become much higher much faster all over the world. Renewable electricity will become cheaper and more abundantly available, as will green hydrogen production and biomethane, including from gasification.
- In the Global Climate Action Pathway, technology costs will decrease faster, both on the demand side (e.g. chemical industry decarbonisation and hydrogen trucks) and the supply side (e.g. in biomethane from gasification and imported green and blue hydrogen). This provides a major upside compared to the Accelerated Decarbonisation Pathway.

The Accelerated Decarbonisation Pathway is based on the assumptions that decarbonisation of the EU energy system is largely driven by governments and companies within the EU, and that renewable and low carbon gases almost exclusively come from domestic EU sources. However, developments for the different sectors can also go slower or move in different directions. If so, this increases the need for alternative technologies or poses additional pressure on other sectors.

This chapter describes the potentially different developments in the supply of biomethane and hydrogen, as well as in the decarbonisation of buildings, industry, transport, and power generation. Next, it provides insights in the Global Climate Action Pathway, which details how decarbonisation can be accelerated if countries around the world act towards meeting the Paris Agreement goals.

To unlock Europe's full biomethane potential, tens of thousands of European farmers must adopt sustainable agricultural cultivation practices that enable sustainable sequential cropping of biogas feedstock. The technology development of thermal gasification plants is essential. When these developments fall behind, this will impact the amount of biomethane available in the system. The lower production of biomethane within the EU means that biomethane should be imported (e.g. from Ukraine and Belarus) or be compensated through other low carbon options, such as the increased deployment of hydrogen, stronger electrification, or increased use of other bio-energy carriers. Therefore, the resulting energy system must deal with higher import dependencies, more blue hydrogen for longer periods, stronger electrification, and likely increased energy system costs. The resilience and robustness of the overall pathway can be ensured by scaling up biomethane rapidly: if developments in energy efficiency and renewable electricity generation fall short, sufficient biomethane will ensure that no fossil energy is needed as alternative.

The hydrogen economy is in its infancy. The development of blue hydrogen in the current decade is key for reaching the 2030 target, limiting cumulative CO_2 emissions, and the expansion of hydrogen technologies in the various demand sectors, thus paving the way for the use of green hydrogen in the 2030s. If deployment falls behind, this will hinder hydrogen's role in the decarbonisation of the EU energy system. Future use of green hydrogen also depends on its availability. Scaling up of wind and solar in Europe is of key importance: If sufficient capacity is not developed in addition to what is needed for direct electricity consumption, which already requires a jump in annual capacity additions, Europe will have to rely on importing green hydrogen or it will need to develop even more blue hydrogen production. Consequently, the transition towards a fully renewable energy system will take more time.

Achieving full decarbonisation of Europe's buildings is challenging because of the long renovation cycle and a large number of individual actors. In the next decades, renovation rates should increase strongly. If such a renovation wave stays behind, this hinders the deployment of all-electric heat pumps in buildings without gas or district heating connection. It also lowers the potential benefits of the hybrid heat pump, because the share of heat that can be covered with electricity will be lower. In this case it will be important to keep attention on a possible alternative: to focus less on insulation and more on renewable heating technologies. For example, hydrogen fuel cells, gas heat pumps, or boilers could be applied in specific situations where (hybrid) heat pump application turns out to be difficult. These technologies could also be applied in combination with limited insulation, although this will put additional pressure on the supply of low carbon renewable gases and on the possibility to use them in other sectors.

Industry's decarbonisation relies on the development of new, low carbon production technologies. Several investments in industry will happen in this decade. If new technologies are not ready at scale early enough, it means that there will be fewer deployments of low carbon production technologies until 2050, increasing the need to apply CCS across industry, decarbonise the fuel (such as using biofuels or synthetic fuels), or mitigate remaining emissions by additional negative emissions in other sectors, for example though bio-energy with carbon capture and storage (BECCS) and soil organic carbon accumulation.

Decarbonising road transport and shipping is possible through different energy carriers, such as electricity, bio-CNG, bio-LNG, ammonia, hydrogen, and even liquid biofuels. In case electrification of light transport, development of fuel cells in heavy transport, or the deployment of bio-LNG in heavy transport and shipping is slower than envisioned, this will increase the need for the other energy carriers, like the use of liquid biofuels or even more bio-CNG and bio-LNG in road transport, which puts pressure on the available biomass.

For shipping, the extent to which bio-LNG is the most economical option depends on how alternative technologies (like ammonia fuel cells) develop, and to what extent existing LNG fuelling infrastructure is sufficient to meet demand in 2050. Ships invested in today will likely be part of the 2050 fleet. When new low carbon technologies come to market, ship owners may choose to accelerate write-off or retrofit their fleet. A sensitivity analysis included in Appendix 5 provides indications that, after BEV, bio-LNG may possibly not always be the most economic fuel to decarbonise a ship. Ammonia-based propulsion systems could be a way forward as well, depending on the size and operating conditions of the ship in question. However, other factors besides operating costs, such as safety of operation, NOx emissions, and toxicity and perception thereof, are critical for large-scale deployment. The global sector is undergoing a transformation to lower emitting fuels and is witnessing aggressive cost reductions of low carbon technologies. If ammonia fuel cells were to gain market share in long-distance shipping, this reduces the demand for bio-LNG in the shipping sector but increases the demand for hydrogen to produce ammonia within or outside Europe. A reduction in bio-LNG demand in shipping presents opportunities to use more renewable methane in other sectors, such as the buildings or power sectors, or gives robustness to the decarbonisation pathways in case renewable methane production does not reach its full potential by 2050.

Major upside when other parts of the world join in the development: The Global Climate Action Pathway

While developments can be slow and go in different directions, it should be noted that the Accelerated Decarbonisation Pathway does not depend directly on what happens in other parts of the world. However, 195 countries around the world joined the Paris Agreement, and they all face the challenge of rapid decarbonisation in coming decades. The challenges vary by region, but there are similarities regarding the energy system. If countries around the world work towards meeting the Paris Agreement goals, high shares of renewable energy will play a major role, and so will electrification. In many places, the role that renewable and low carbon gases can play is increasingly recognised. Examples include interest in biogas and biomethane in China, hydrogen initiatives developing worldwide, and the debate on the future role of gas emerging in North America.

Developments can go significantly faster when other parts of the world join in the development of renewable and low carbon gas

Decarbonisation efforts within the EU will create positive external effects such as knowledge transfer and economies of scale that are likely to accelerate global carbon action. The announced introduction of a carbon border adjustment mechanism, while motivated by the necessity to avoid carbon leakage despite elevated future carbon prices in the EU ETS, will also inevitably serve as an incentive to decarbonise economies outside the scheme, to the extent that these economies are exporting to countries participating in it.

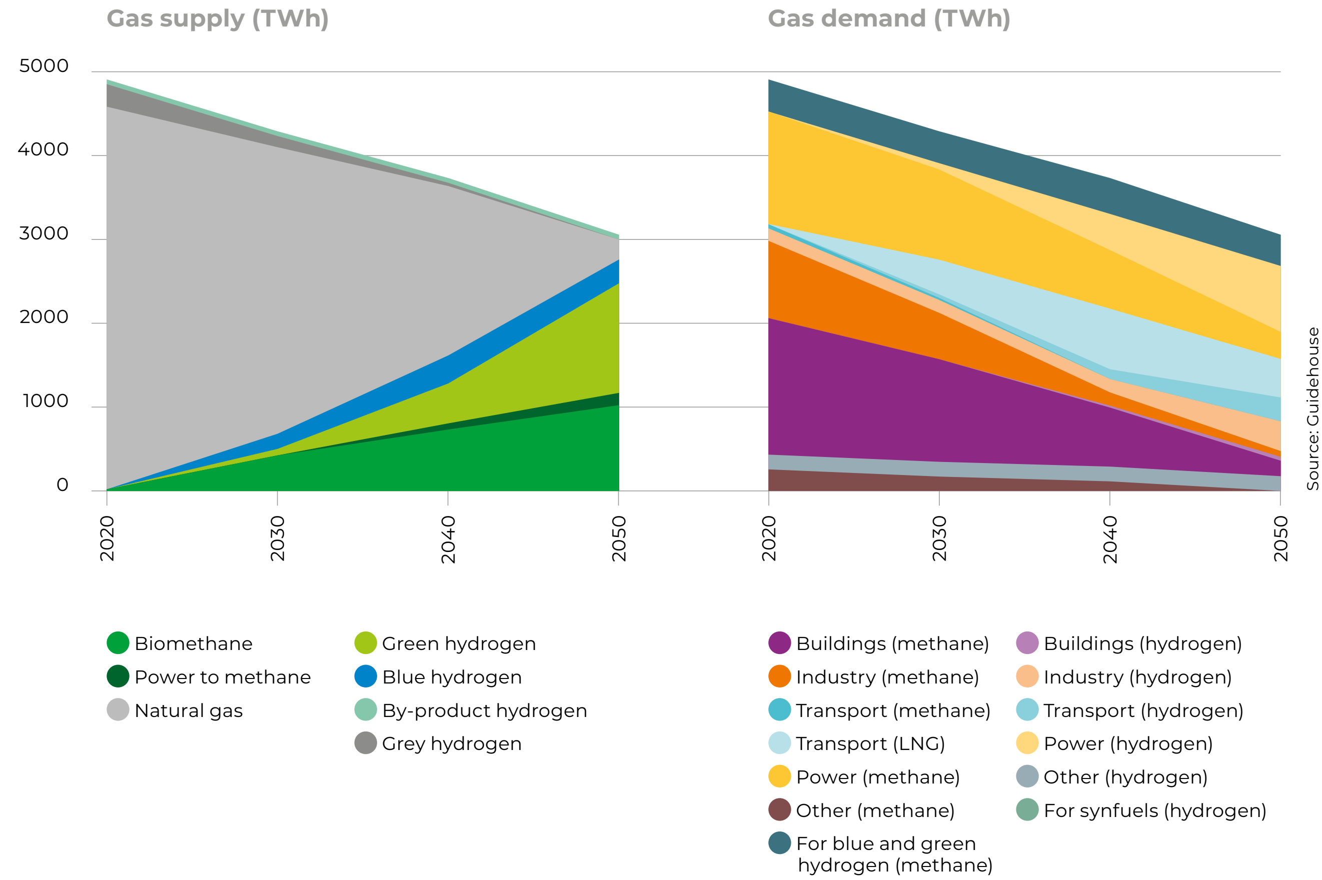
The Global Climate Action Pathway explores how increased climate mitigation actions in other continents can be beneficial for the speed, scale, and cost of renewable and low carbon gas developments in the EU's energy transition. Global innovation efforts speed up the market readiness of novel technologies. Technology costs will decrease faster on the demand side (e.g. MTO and hydrogen trucks) and the supply side (e.g. in biomethane from gasification and green and blue hydrogen). This provides a major upside for the societal costs of the energy transition compared to the Accelerated Decarbonisation Pathway. For example, with aggressive reductions in capital costs for electrolyser systems and renewable power, production costs for green hydrogen could fall to €14–€32/MWh by 2050, i.e. below €1/kg.[108] Such steep reductions in

108 For assumptions see Appendix 2. Estimates are in line with e.g. Bloomberg NEF (2020). *Hydrogen Economy: Key Messages*. https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf

cost compared to the Accelerated Decarbonisation scenario could lead to several decarbonisation measures becoming cost-effective much earlier in time. Before 2040, a switch from fossil fuels to green hydrogen can become cost-effective in the steel industry, cement, ammonia but also in gas-fired power generation. When green hydrogen reduces in cost globally, it may be more cost-effective for some industries to import synthetic hydrocarbon fuels rather than sourcing this domestically or importing pure hydrogen. Examples of such fuels for which global shipping infrastructure already exists today are kerosene, ammonia and methanol.

Innovation will accelerate decarbonisation in industry and transport through emerging technologies. Global climate efforts will also have a strong impact on the cost of green hydrogen and biomethane through economies of scale that can be realised along the supply chain. Biomethane and hydrogen cost reductions impact infrastructure by accelerating the transition towards a decarbonised energy system. Hydrogen supply will surpass regional demand by 2030 and will require the development of an EU hydrogen backbone to connect supply to demand that is further away. At the same time, global developments drive the large-scale imports of synthetic chemicals and synthetic fuels, which will reduce the capacity required for the transmission grid as not all hydrogen needs to be produced within Europe. As a result, total gas demand in the Global Climate Action Pathway will reduce faster than in the Accelerated Decarbonisation Pathway, but its value remains in buildings, industry, transport, and power generation.

Figure 30. Gas supply and demand in the Global Climate Action Pathway



Disclaimer

This report was prepared by Navigant Netherlands B.V.. Please note that per 11 October 2019 Navigant was acquired by Guidehouse. This new combination bolsters our capabilities to serve you even better. We continue operating without changes to our company data, such as financial information and VAT-number, but we expect that in April 2020, we will change the name of our legal entity to Guidehouse Netherlands B.V.. For the avoidance of doubt, our name change does not have any legal impact; from our side the same party remains a party to the contract with you, as only the name of our legal entity changes.

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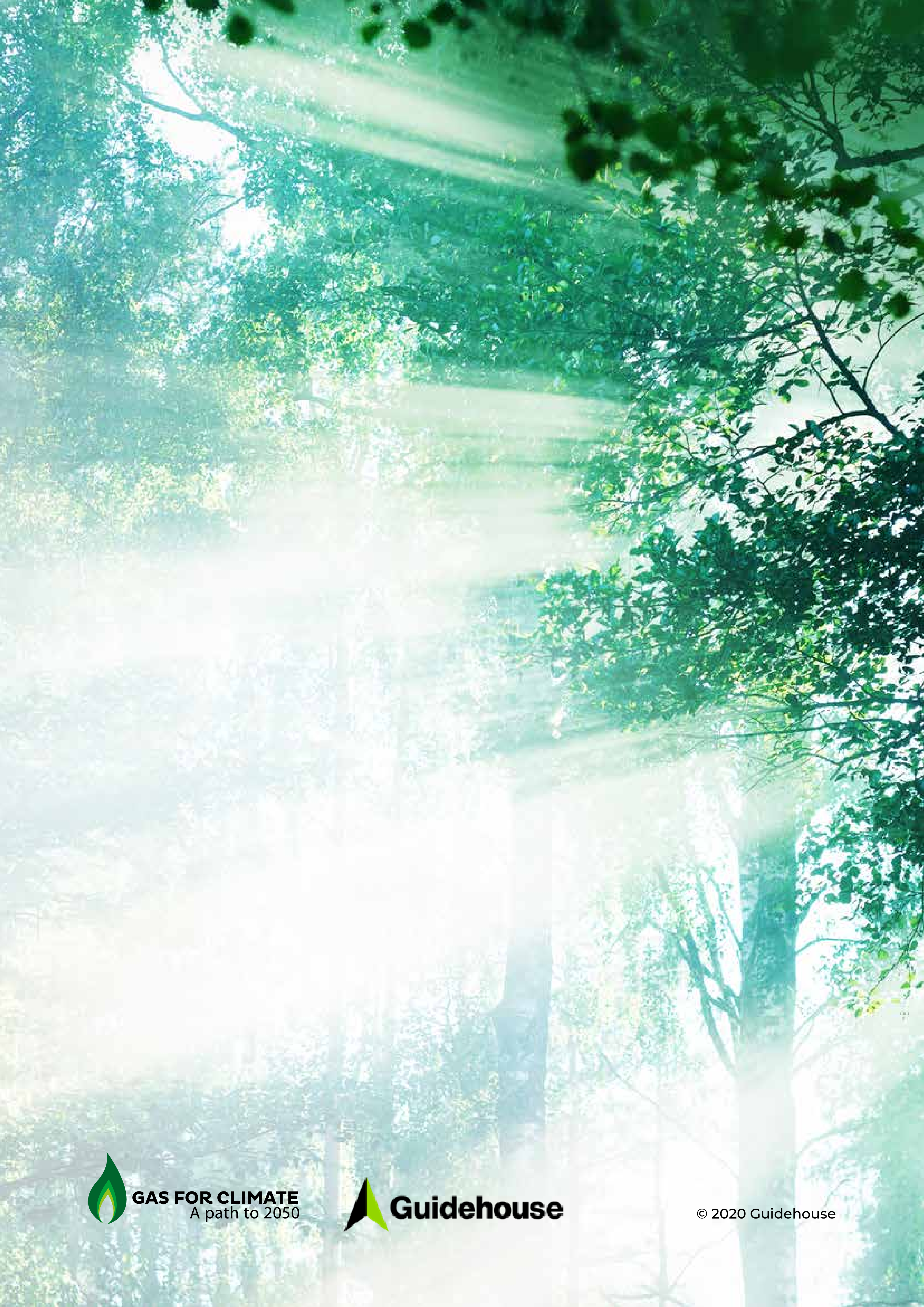

GAS FOR CLIMATE
A path to 2050

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