Agora Energiewende

Agora Industry

IMPULSE

Low-carbon hydrogen in the EU

Towards a robust EU definition in view of costs, trade and climate protection

Please cite as:

Agora Energiewende and Agora Industry (2024): Low-carbon hydrogen in the EU. Towards a robust definition in view of costs, trade and climate protection.

Impulse
Low-carbon hydrogen in the EU. Towards a robust definition in view of costs, trade and climate protection.

Written by
Agora Energiewende and Agora Industry
Anna-Louisa-Karsch-Straße 2 | 10178 Berlin
T +49 (0)30 700 14 35-000

www.agora-energiewende.de
info@agora-energiewende.de

www.agora-industry.org
info@agora-industrie.de

Underlying Market Modelling
Deloitte Finance
6 Place de la Pyramide
92908 Paris La Défense Cedex | France
Telephone: +33 (0)1 40 88 28 00
www.deloitte.fr
Manuel.villavicencio@deloitte.fr

Underlying Research On Fossil Based Low Carbon Technologies
Carbon Limits
C J Hambros plass 2
NO-0164 Oslo | Norway
+46 73 925 51 76
http://carbonlimits.no/
malavika.venugopal@carbonlimits.no

Project lead
Michaela Holl | Michaela.Holl@agora-energiewende.de
Veerle Dossche | Veerle.Dossche@agora-industrie.de

Authors
Michaela Holl, Matthias Buck (both Agora Energiewende); Veerle Dossche, Matthias Deutsch, Leandro Janke (all Agora Industry)

Acknowledgements
This analysis would not have been possible without the dedication and professionalism of colleagues from Deloitte Finance, Carbon Limits, ICCT and contributions by numerous Agora colleagues. We would in particular like to thank Johannes Trüby, Manuel Villavicencio, Aurélien Ailleret (all Deloitte); Malavika Venugopal, Fanny Lagrange, Gaelle Cauchois (all Carbon Limits); Chelsea Baldino (ICCT); Frank Peter, Mathias Koch, Zaffar Hussain, Julian Somers, Frank Jordans, Darlene D'Mello (all Agora Industry); Christian Redl, Kaisa Amaral, Susanne Liebsch, Simon Müller (all Agora Energiewende).

Preface

Dear reader,

All climate neutrality scenarios foresee a role for hydrogen, particularly in applications where direct use of clean electricity is currently not an option. However, whether hydrogen use increases or reduces greenhouse gas emissions depends on the way it was produced.

The new EU Hydrogen and Decarbonised Gas Markets Directive obliges the European Commission to adopt a delegated act with a methodology for assessing greenhouse gas emissions savings from low-carbon fuels. This methodology will be central to the integrity of the Fit for 55 framework and it will determine the future cost-competitiveness of renewable hydrogen.

Low-carbon hydrogen is produced in different pathways that come with distinct technology costs, emission profiles and regulatory challenges. Several technical and economic issues must be solved if low-carbon hydrogen is to make a positive contribution to Europe's transition to climate neutrality.

There is no low-carbon hydrogen shortcut into a climate-neutral future! To ensure that low-carbon hydrogen actually comes with low greenhouse gas emissions throughout the entire value chain requires real political commitment and significant investments.

We hope you enjoy the read and look forward to a fruitful exchange on this important topic!

Matthias Buck
Director Europe, Agora Energiewende

Frank Peter
Director, Agora Industry

Key findings at a glance

1 **Hydrogen will be critical to decarbonise hard-to-electrify applications particularly in industry.** While the EU should prioritise renewable hydrogen, low-carbon hydrogen could be cost competitive and sufficiently decarbonized over the next two decades. This requires upstream emissions to be effectively abated, highly efficient carbon capture technologies to become available at scale, and infrastructure for transport and permanent storage of captured CO_2 to be built.

2 **It depends on the CO_2-intensity of the electricity used if grid-based hydrogen will be low carbon.** Operating an electrolyser 24/7 with grid-drawn electricity can today result in more emissions than producing conventional fossil hydrogen. In 2023, this would have been the case in 15 EU member states. Grid-based low-carbon hydrogen production should require accounting of actual hourly greenhouse gas emissions, rather than annual averages or default values. This would also incentivise investments into clean electricity and mirror conditions of renewable hydrogen producers.

3 **Fossil-gas-based hydrogen would qualify as low carbon if upstream abatement and carbon capture rates combined achieve a 70 percent reduction of emissions compared to fossil fuel or 3.38 $kgCO_2eq/kgH_2$.** Meeting the 70 percent threshold with available CCS technology would today only be possible with fossil gas supplied by Norway. To incentivise best available technologies (BAT) to abate upstream emissions and ensure investments into CCS with capture rates of >90 percent, the greenhouse gas threshold for low-carbon fuels should be progressively reduced to 1 $kgCO_2eq/kgH_2$ by 2050.

4 **By the mid 2030s, grid-based hydrogen will be either renewable or low carbon in most parts of Europe as the electricity mix will have a low-emission intensity.** Low-carbon hydrogen produced on the basis of fossil gas with BAT and CCS will be part of the transition for some time, especially in countries with fewer renewables. However, grid-based low-carbon hydrogen should be prioritised in Europe as it offers greater climate integrity and energy security compared with fossil-based alternatives.

Content

Executive Summary

All climate neutrality scenarios foresee a role for hydrogen, particularly in applications where direct use of clean electricity is currently not an option. However, hydrogen is not a clean source of energy like the sun or wind – it is an energy carrier. The way hydrogen is produced determines whether its use increases or reduces greenhouse gas emissions. As of 2022, more than 90 percent of hydrogen in Europe was produced with fossil gas through unabated methane reforming resulting in high greenhouse gas emissions.

Given the slower-than-anticipated scale-up of renewable hydrogen (and derivatives) projects and their higher-than-expected costs, other options to meeting growing hydrogen demand in Europe move to the fore – including imports or the production of fossil-based low-carbon hydrogen in Europe. The new EU Hydrogen and Decarbonised Gas Markets Directive obliges the European Commission to develop detailed requirements on what qualifies as low-carbon fuels in Europe in a forthcoming delegated act.

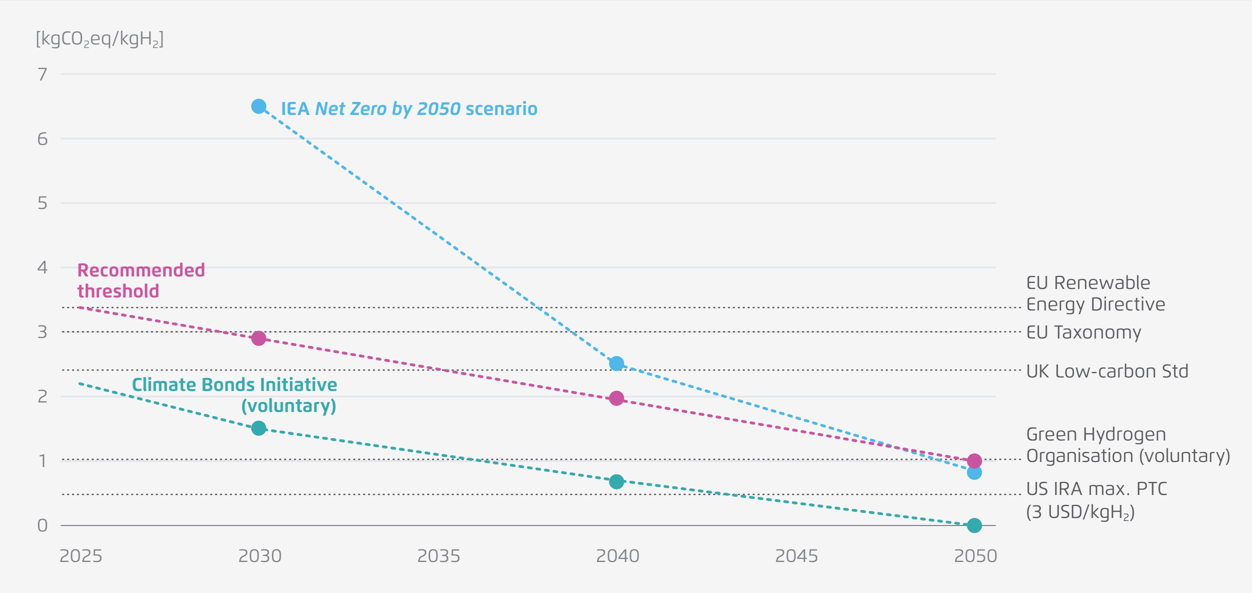
It is important to distinguish between different production pathways of low-carbon hydrogen that will fall under this definition, as they come with distinct technology costs, emission profiles and regulatory challenges: (i) natural gas reforming with carbon capture and storage (CCS) (ii) low-carbon hydrogen produced through electrolysis with electricity drawn from the grid (iii) imports of low-carbon hydrogen or imports of fossil gas used for producing low-carbon hydrogen in Europe. It is also important to consider the interaction of low-carbon fuels production with the production of biogas and biomethane.

Throughout the next two decades, the costs of renewable hydrogen will be at the higher end compared with fossil-based production, with country-specific differences. While renewable hydrogen produced in Spain will reach cost parity around 2045, this would – depending on gas price assumptions – not be the case for Germany.

Even when adding transport costs, imported renewable or low-carbon hydrogen or imported fossil gas to produce low-carbon hydrogen in Europe, could outcompete unsubsidised renewable hydrogen production in parts of Europe that are less well endowed with low-cost renewables, according to the modelling done for this analysis. Notably, however, the cost-difference does not factor in investments to mitigate greenhouse gas emissions in third countries.

The future EU low-carbon fuels methodology will add to a growing body of national and international standards – some obligatory, some voluntary – on the greenhouse gas intensity of hydrogen. The starting point of the EU methodology (70 percent reduction compared with the fossil fuel comparator, that is 3.38 $kgCO_2eq/kgH_2$) is among the less ambitious benchmarks from a climate protection perspective. The starting point, the Commission's explicit mandate to be more ambitious ("at least"), the EU's commitment to reach climate neutrality by latest 2050, the need to scale up CCS and economic incentives underlying different hydrogen production pathways – shown by the modelling for this report – all align with our **main recommendation, namely that the EU should set from the start a dynamically decreasing maximum greenhouse gas threshold for low-carbon fuels, starting with 3.38 $kgCO_2eq/kgH_2$ (the current threshold) to reach 3 kg (referred to in the EU taxonomy) by 2030, 2 kg by 2040 and 1 kg by 2050.**

Recommended dynamic threshold for the GHG intensity of hydrogen → Fig. 1



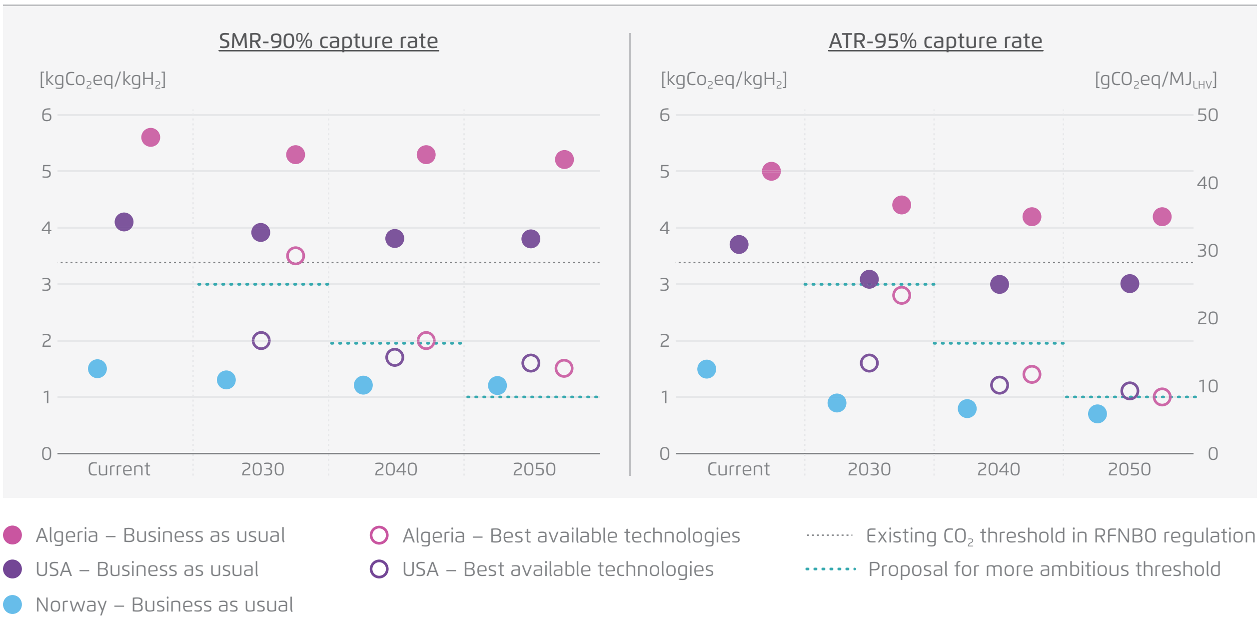
Agora Energiewende and Agora Industry (2024). Notes: The system boundaries and implementation details of these standards and requirements differ. The numbers for 2030 and 2040 have been rounded in the text accompanying this figure. The exact numbers used in Deloitte's modeling are 2.90 (2030) and 1.95 (2040) $kgCO_2eq/kgH_2$.

To ensure that **grid-based hydrogen** is low-carbon and allows for renewable hydrogen to compete on fair terms, **we recommend that the future delegated act on low-carbon fuels establish the greenhouse gas emissions of the marginal power-producing unit as the only way to determine the carbon content of low-carbon production.** This should be applicable at the latest by 2030, when renewable-hydrogen producers are required to move to hourly matching. The modelling done for this analysis shows that more accurate accounting would not only result in additional greenhouse gas emissions savings of 29 $MtCO_2eq$ until 2050, but also boost the market-based upscaling of electrolysers in the EU with one-third more installed capacity by 2030 compared with a more lenient method that allows accounting based on country-wide yearly average carbon intensity of the power mix in the grid. Furthermore, to avoid double counting of renewables in the reference power mix, **we recommend subtracting renewable electricity under power purchase agreements (PPAs) for hydrogen production, before calculating the carbon intensity of the power mix used for producing grid-based low-carbon fuels.**

From a climate-integrity and a security-of-supply perspective it is concerning that the **fossil-gas based route of producing low-carbon hydrogen** builds on several preconditions that are currently not met. First, it presupposes that countries supplying fossil gas will put in place measures to effectively control upstream emissions (mainly methane, but also CO_2). Second, it presupposes sufficient capacity of carbon-capture technologies at the sites producing low-carbon hydrogen with efficiency levels of capturing carbon that are currently not available in the market. Third, it presupposes the availability of infrastructure for transporting the captured carbon from the point of capture to where it can be stored. Lastly, it presupposes sufficient geological storage capacity to inject and permanently store the captured carbon.

As regards the controlling of upstream greenhouse gas emissions, **we recommend complementing the default upstream emission factor of 9.7 gCO_2eq/MJ by country-specific, preferably by basin-specific, emissions factors, until site-specific rules under the EU Methane Regulation come into effect.** Not doing so would underestimate real-world emissions from fossil-based hydrogen by a factor of 2.5 for Europe by

Carbon footprint of fossil gas-based hydrogen produced in Germany as a function of fossil gas origin → Fig. 2



Deloitte for Agora Energiewende and Agora Industry (2024) based on data from Carbon Limits.

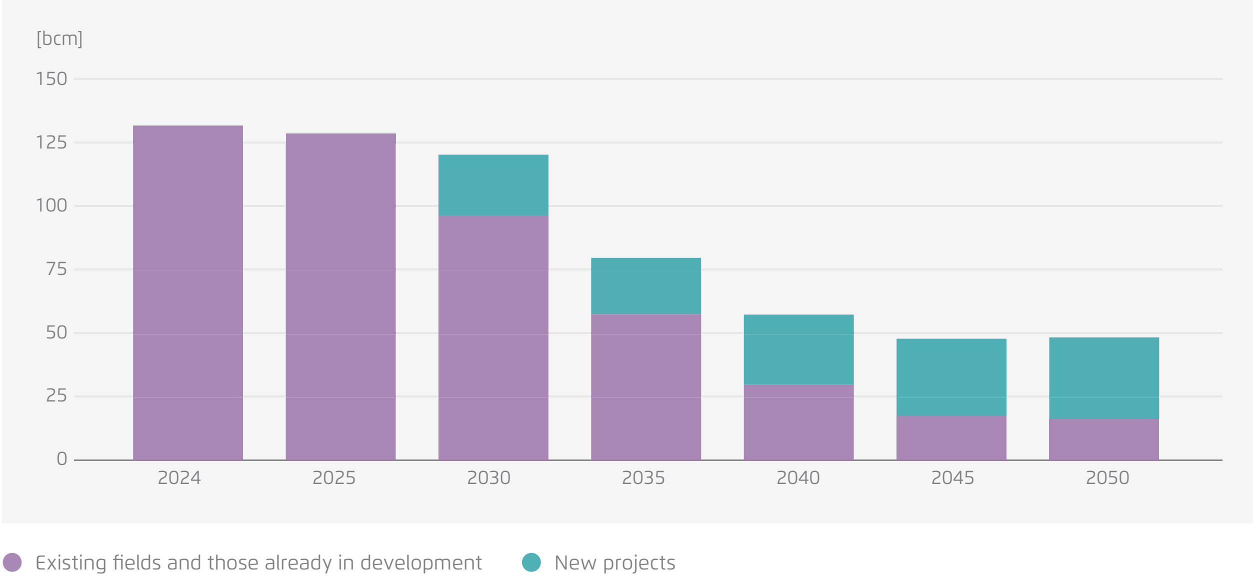
2040. Although best available technologies (BAT) and relevant behavioural measures exist to abate methane and CO_2 emissions along the fossil-gas value chain, Europe's main fossil-gas suppliers – except for Norway – are currently far from abating methane and CO_2 emissions at levels to use fossil gas delivered to Europe for producing low-carbon hydrogen. Figure 2 illustrates that fossil gas imported from e.g. US and Algeria could currently not be used for producing low-carbon hydrogen in Germany as upstream emissions are too high.

This also means that Europe could become heavily reliant on a very limited number of suppliers of fossil gas for hydrogen production if currently lacking efforts to implement BAT along the value chains were to reflect a broader trend. With fossil-gas production in Norway projected to decline sharply after 2030 despite new project developments (see Figure 3), we **observe that the fossil-gas based low-carbon hydrogen route currently adds a significant risk to Europe's future energy security.**

High performing CCS technologies of 95 percent and above capture rates are being announced – with the most promising technologies like ATR at technology readiness level 5 – and would come at higher cost. In view of achieving climate neutrality by latest 2050 and to provide an incentive for rapid deployment of high performing CCS technologies such as ATR, we recommend setting a dynamically decreasing maximum greenhouse gas threshold for low-carbon fuels, starting with 3.38 $kgCO_2eq/kgH_2$ (the current threshold) to reach 3 kg (referred to in the EU taxonomy) by 2030, 2 kg by 2040 and 1 kg by 2050. At this point, **the availability of highly efficient carbon capture technologies at scale and reasonable cost is a bottleneck in the fossil-gas based 'low-carbon' hydrogen route.**

As regards transporting and permanently storing the captured CO_2, the recently adopted EU Net Zero Industry Act sets the target to create geological storage with a CO_2 injection capacity of 50 Mt annually by 2030. **We recommend that the low-carbon fuels methodology should prioritise the permanent geological storage of the captured CO_2 and not allow other methods such as carbon capture and use**

Projected fossil gas production in Norway → Fig. 3



Rystad Energy, drawn from Oil Change International (2024).

applications or "Enhanced Oil Recovery" that either are not permanent or may even increase greenhouse gas emissions from a life-cycle perspective.

As regards greenhouse gas accounting and offsetting, **we recommend calculating the carbon content separately for fuels derived from fossil gas, fuels derived from biogases and fuels derived from grid-based electricity.** Allowing mixing and offsetting not only would complicate monitoring and verification of actual carbon content of low-carbon fuels, but also would create perverse incentives from an energy-transition perspective. First, public subsidies for the use of low-carbon fuels would be less effective in triggering investment into highly efficient carbon-capture technologies and into BAT along the value chain. Second, blending and offsetting would undermine the competitiveness of electricity-based low-carbon fuels. Third, such a system would incentivise the blending of biogases to produce low-carbon hydrogen. It would therefore pull increasingly scarce bioenergy resources away from less subsidised, high-value, uses (such as feedstock in industrial value chains), which would be at odds with the EU's net-zero pathway.

Specifically on biogases, the current EU framework limits the scale of food and feed-based feedstocks only in the transport sector and does not regulate minimum waste and residue shares. The current framework also does not address biogas/-methane leakage. **We recommend that, before allowing for any role of biogases in low-carbon fuels production, the EU should establish clear obligations on monitoring, reporting and verification of biomethane leakage at site level.** Furthermore, while 100 percent bio-hydrogen will not be cost competitive, the blending of biomethane could occur, particularly if offsetting by use of certificates would be allowed. Against this background, **we recommend that renewable and low-carbon feedstocks are separately accounted for and separately certified. Furthermore, only waste and residue-based biogases should be eligible for low-carbon fuels production.**

Given the significant, but indirect role of hydrogen in warming the climate and the highly volatile nature of hydrogen molecules, **we recommend that the EU follow the example of the UK and establish from the start an obligation to employ BAT for hydrogen leakage control as part of the low-carbon fuels accounting methodology.** Both hydrogen leakage and the high short-term warming potential of methane (a consideration that leads some scientists to argue for a 20-year rather than a 100-year perspective when assessing its contribution to climate pollution) were not addressed in the modelling underpinning this analysis. Our findings will therefore underestimate the true climate impact of the fossil-based hydrogen value chain.

Considering the importance of international standards, **we also recommend that the EU engages in international partnerships, for example with the UK and the US, to establish scientifically sound methodologies and standards for low-carbon hydrogen and fuels,** based on independently verified reporting of emissions, as well as regulatory dialogues to manage the emerging restructuring of value chains and new trade maps. Life-cycle accounting for both renewable and non-renewable fuels should be continuously developed in the future, for example to cover embodied emissions and include hydrogen leakage.

Overall, we strongly recommend that the EU's low-carbon fuels methodology and policy framework should steer investments into grid-based production pathways, as by the mid 2030s electrolysers operating continuously should produce either renewable or low-carbon hydrogen almost everywhere in Europe. Whilst the EU can control the rapid scaling of renewable power in the mix, it cannot control whether major fossil-gas suppliers will implement BAT for abating methane and CO_2 emissions along the value chain. Furthermore, fossil-gas based low-carbon hydrogen will not be available in the short-term, not even based on Norwegian gas, given the absence of infrastructure for transporting and permanently storing the captured carbon.

It is welcome that the debate on renewable hydrogen increasingly takes a realistic outlook on its availability and costs. Now, it is equally important, that the public debate on the potential role of low-carbon hydrogen in the transition assesses realistically all associated risks, including the risk of keeping a fossil-fuel dependency that potentially puts Europe's energy security at risk.

Introduction

Hydrogen is widely regarded as a "clean fuel" since it is carbon free at the point of use. All climate neutrality scenarios foresee a role for hydrogen, particularly in applications where direct use of clean electricity is currently not an option (e.g., some industrial processes, seasonal storage in the power system and long-haul shipping and aviation). To kick-start hydrogen value chains, the European Union (EU) and national governments offer significant subsidies for investments into hydrogen production, hydrogen demand and the building of hydrogen transport infrastructure.

However, hydrogen is not a clean source of energy like the sun or wind – it is an energy carrier. **The way hydrogen is produced determines whether its use increases or reduces emissions of greenhouse gases (GHGs).** In fact, as of today, hydrogen production is amongst the most greenhouse gas emissions-intensive activities in Europe, resulting in the annual release of 70–100 million tons of carbon dioxide (CO_2)[1].

In February 2023, the EU established a methodology with detailed rules on what qualifies as renewable hydrogen in Europe.[2] After a phase-in period to support early scale-up of electrolyser projects, these rules will ensure that renewable hydrogen sold in Europe is demonstrably produced with renewable electricity. However, given the slower-than-anticipated scale-up of renewable hydrogen (and derivatives) projects and their higher-than-expected costs, other options for meeting growing hydrogen demand move to the fore – including imported hydrogen or the production of fossil-based low-carbon hydrogen.

This shift in priorities puts the spotlight on a forthcoming European Commission delegated act under the new EU Hydrogen and Decarbonised Gas Markets Directive that will set out detailed requirements on what qualifies as low-carbon fuels in Europe (see also Box 1). This definition will go a long way towards determining the integrity of the *Fit for 55* framework as it is being implemented. The definition will determine whether industrial users can credibly make claims about the "low-carbon" character of their products and it will establish the future cost competitiveness of 'green' hydrogen produced

1 A hydrogen strategy for a climate-neutral Europe. COM(2020) 301 final.

2 Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023.

Box 1: Metrics used for low-carbon fuels

The EU Delegated Acts on renewable fuels of non-biological origin 2023/1184 and 2023/1185 define greenhouse gases emission thresholds based on a fuel energy basis, namely gCO_2eq/MJ (GWP 100). However, the industry and international organisations often describes hydrogen related GHG emissions based on the fuel mass as $kgCO_2eq/kgH_2$. Whenever possible, the diagrams shown in this report display both units to facilitate the interpretation of results. For this purpose, a conversion factor of 0.12 based on the lower heating value of H_2 (120 MJ/kgH_2) is used to convert from gCO_2eq/MJ to $kgCO_2eq/kgH_2$ as follows:

- → Fossil fuel comparator (FFC): 94 gCO_2eq/MJ equal to 11.28 $kgCO_2eq/kgH_2$
- → 70 percent emission reduction from FFC: 28.20 gCO_2eq/MJ equal to 3.38 $kgCO_2eq/kgH_2$

with renewable electricity. It will also determine the degree to which the EU will continue to depend on fossil-gas imports and be exposed to gas-price volatility.

As a starting point for the debate on defining low-carbon fuels, it is important to distinguish between different production pathways that will fall under this definition, as they come with distinct technology costs, emission profiles and regulatory challenges:

- → **Natural gas reforming with carbon capture and storage (CCS):** This is often referred to as the least-cost production pathway in the short term. However, such expectations build on several preconditions that are currently not yet met: that emissions of methane but also CO_2 are effectively abated at high levels along the entire fossil-gas value chain from production over transport to use, that carbon capture technologies perform at high efficiency levels that are currently not available at scale, and that CO_2 transport infrastructure and sufficient capacity for permanent geological storage of captured CO_2 are available in time.
- → **Low-carbon hydrogen produced through electrolysis with electricity drawn from the grid:** This would be electricity-based hydrogen that does not meet the requirements of the EU methodology for renewable hydrogen[3] and remains below a certain emissions-intensity threshold. Due to the legacy power mix in EU countries and the fact that additional power demand for hydrogen production is met by the marginal unit generating electricity, hydrogen produced with grid-drawn electricity may result in specific emissions exceeding those of unabated fossil fuels. In the EU, only France and Sweden would currently be able to produce low-carbon hydrogen with a carbon footprint below 3.38 kilogrammes of CO_2 equivalent per kilogramme of hydrogen, reflecting a 70 percent reduction compared to the unabated fossil reference (11.28 $kgCO_2eq/kgH_2$). Importantly, however, due to the rapid increase in the share of renewable power in the mix, grid-based hydrogen production in most parts of Europe should result in hydrogen that meets the low carbon threshold by the mid 2030s.
- → **Imports:** The Commission's delegated authority under the Gas Directive requires that the accounting rules consider emissions along the entire value chain. This means that the future EU standard will also apply outside the EU. Imports of fossil gas used for producing low-carbon hydrogen in Europe would have to demonstrate effective abatement of upstream emissions along the value chain and imports of low-carbon hydrogen (or its derivatives) would have to demonstrate compliance with the relevant EU's methodology at the place of production and during transport. Imports will happen if source countries cooperate to ensure environmental integrity along the entire fuels value chain and suppliers see cost advantages.

When defining low-carbon fuels, it is also important to consider the interaction of their production with the **production of biogas and biomethane**. While biogas and biomethane qualify under EU law as renewable gases, not as low-carbon fuels, there are suggestions for blending or for statistical offsetting of unabated fossil fuels with biogas or biomethane to render it low carbon; this would have an effect on the competitiveness of other pathways.

To support a debate on the forthcoming Commission delegated act, Agora Energiewende and Agora Industry commissioned consultancies Deloitte and Carbon Limits to address the different elements of the low-carbon fuels landscape with a focus of the analysis on low-carbon hydrogen and its interaction with renewable hydrogen. Carbon Limits has mapped out technology costs, technology developments and life-cycle emissions for different low-carbon fuel production pathways, linking them to likely EU import scenarios (Norway, Algeria and the US). The International Council on Clean Transport (ICCT) contributed data points on biogases. Based on this, Deloitte modelled the potential contribution of low-carbon fuel imports to Europe in view of current and future production costs of low-carbon and

3 See footnote 2

renewable hydrogen produced through electrolysis in Europe. The modelling work of Deloitte is published as a self-standing report.

This paper builds on the analytical work of Deloitte and Carbon Limits. However, the policy recommendations set out in this paper are our own.

We provide recommendations for the EU's future definition of low-carbon fuels for both grid and fossil-based production pathways, taking into account existing reference points in EU legislation, most importantly the 2023 delegated act on a life-cycle emission methodology for renewable fuels of non-biological origin and recycled carbon fuels[4] and current or emerging standards and verification schemes.

4 Commission Delegated Regulation 2023/1185

1 Different hydrogen production pathways, their costs and their associated life-cycle emissions

Hydrogen can be produced using a number of processes. Unabated methane reforming, predominantly steam methane reforming (SMR) – with high greenhouse gas emissions – currently accounts for more than 90 percent of hydrogen production in the EU. **As of 2022, less than 1 percent of the hydrogen production capacity in the EU was either electrolysis-based or fossil-based with carbon capture.**[5] This shows the considerable distance to go in order to transform the currently highly polluting hydrogen sector. Other, less established ways of hydrogen production include autothermal reforming (ATR), pyrolysis and biomass gasification[6]. To decarbonise methane-based processes, apart from reducing upstream leakage of both methane and CO_2, the CO_2 associated with production and combustion must be captured and then stored permanently. Fossil-based hydrogen and carbon capture is often referred to as "blue" hydrogen.

Electrolysis works by splitting water molecules into hydrogen and oxygen using electricity. The main electrolysis technologies are alkaline, proton exchange membrane (PEM) and solid oxide electrolysis (SOEC). If the electricity used is from wind, solar or hydro, it is often referred to as renewable or "green" hydrogen and has no emissions from production to consumption. Hydrogen derivatives and e-fuels qualify as renewable if they comply with the criteria set out in the EU methodology for the production of renewable fuels of non-biological origin (RFNBOs)[7] and/or the 2023 delegated act on a GHG methodology for RFNBOs and recycled carbon fuels (RCFs)[8]. Alternative sources of electricity for electrolysis that are less emissions-intensive than conventional, fossil-based production via SMR include non-RFNBO-compliant renewables production, nuclear power and combined cycle gas turbines (CCGT) with CCS.

The multiple production technologies and energy sources come with different emissions intensities, but produce chemically identical hydrogen molecules. The distinction between production routes is often made by associating production options with "hydrogen colours" – green (renewable), blue (fossil with CCS), grey (fossil-based without CCS), turquoise (pyrolysis) and pink (nuclear). Whilst the colour codes can be helpful in indicating the different production pathways and associated challenges, they could also mislead, for example when it is assumed that 'blue' hydrogen will always be sufficiently low carbon.

The EU uses a different hydrogen terminology, categorising supply options depending on the feedstocks:

Low-carbon hydrogen produced through electrolysis in the EU regulatory context refers to all electricity-based hydrogen that does not comply with the RFNBO methodology but respects the 70 percent GHG reduction criteria. In real life, low-carbon hydrogen and renewable hydrogen will be produced in the same electrolyser depending on the ability to demonstrate the renewable character of the electricity used, and respecting the 70 percent GHG-reduction criteria compared with unabated fossil hydrogen for specific periods of operation.

5 European Hydrogen Observatory (2024): The European hydrogen market landscape. Updated February 2024

6 Pyrolysis and geological hydrogen were out of scope of this analysis. Pyrolysis comes with the advantage that its cost can be reduced considerably through selling the solid carbon by-product (also known as "carbon black"). At the same time, this amounts to a form of carbon capture and use and needs careful consideration regarding the net emission reduction. This reduction depends on the exact further use of the carbon and will determine its effective contribution to net-zero ambitions. In addition, pyrolysis requires considerably more electricity than other forms of fossil-based hydrogen production with carbon capture. Therefore, the carbon intensity of electricity is relevant too. If imported LNG were used as a feedstock, the carbon intensity of electricity would need to be below the EU average to produce hydrogen via pyrolysis that complies with the threshold of 3.38 $kgCO_2/kgH_2$ (Hydrogen Europe 2024).

7 Delegated Regulation 2023/1184

8 The EU Delegated Regulation 2023/1185 for a GHG methodology for RFNBOs and RCFs offers additional compliance options to count for fully renewable produce which are not mentioned in the delegated act on RFNBOs.

Low-carbon fuels (including low-carbon gases and hydrogen) is defined in the recently adopted EU Hydrogen and Decarbonised Gas Markets Package as non-renewable and delivering at least 70 percent GHG reduction compared with the fossil fuel comparator referred to in the EU Renewable Energy Directive[9] and in the EU Hydrogen and Decarbonised Gas Markets Package[10].

Biogases/biohydrogen are regulated through the Renewable Energy Directive and defined as renewable but – because of their biological character – not as RFNBOs. Hydrogen produced from renewable biomass would be excluded from the RFNBO definition and targets, but it is promoted under the EU Hydrogen and Decarbonised Gas Market Package. Whilst fully biobased hydrogen might not be cost-competitive, blending it with fossil hydrogen (physically or virtually by means of certificates) could become attractive for a producer. From a net-zero transition perspective, this would set wrong incentives for both fuels. Furthermore, it is important to be aware of the regulatory gaps around biogas and biomethane at EU level: There are currently no provisions governing methane leaks for production of biogas/biomethane and the Renewable Energy Directive only regulates the use of food and feed-based bioenergy in the transport sector, leaving gaps that would need to be closed for proper GHG accounting of biogases and biomethane.

1.1 Costs of different hydrogen production pathways

The costs of both renewables-based and fossil-based hydrogen depend (besides capital expenditures) on operational costs of the input fuel/electricity. The level of future demand also plays a role. Higher demand will increase levelised costs of hydrogen (LCOH). According to the modelling, a lower hydrogen demand scenario would result in 3.26 euros (EUR)/kgH_2 average LCOH in 2030 compared with EUR 3.51/kgH_2 average LCOH if demand is higher. This also suggests that governments that are steering hydrogen offtake to high-priority use cases will save public funding.

As shown in figure 4, fossil gas-based hydrogen production in the near term is amongst the most cost-competitive options (in LCOH) in a large part of Europe. This is based on the assumption of an average EU gas price of EUR 25/MWh over the coming decades and helped in part by long-standing direct and indirect fossil subsidies and an unfavourable gas-versus-electricity price ratio. However, fossil-gas prices are volatile and the future gas price has a significant effect on gas-based production, representing 40–55 percent of the overall costs of generation in 2040. In particular, geopolitical tensions or supply-chain disruptions could cause turmoil in fossil gas markets and undermine the competitiveness of fossil gas-based hydrogen production.

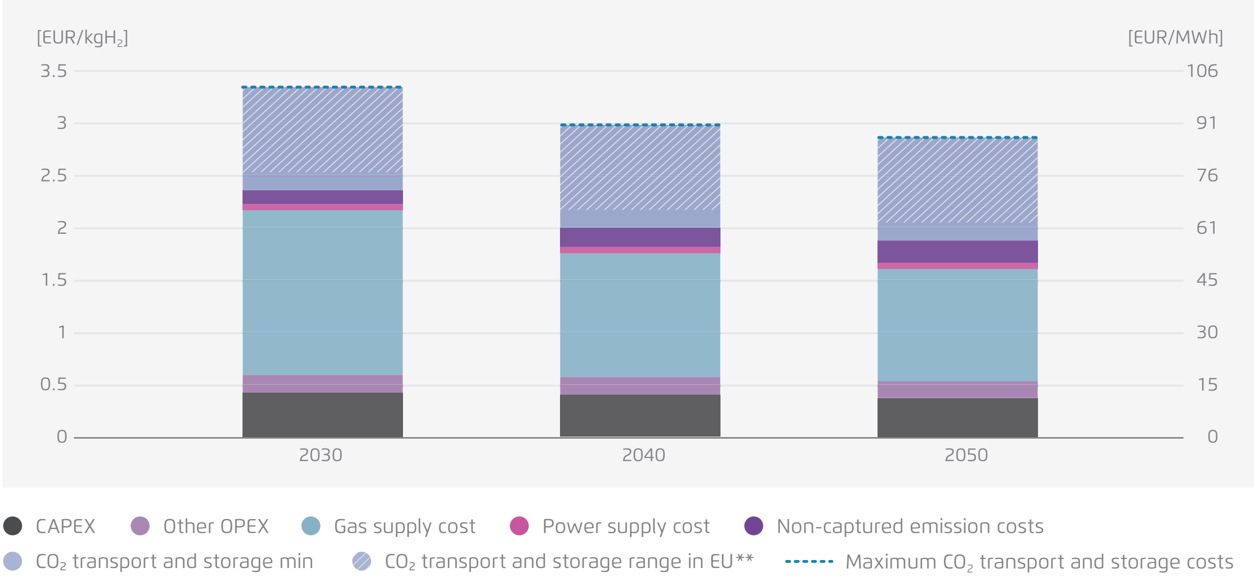
In the case of fossil-based hydrogen production, CO_2 transportation and storage costs add EUR 0.2–1/kgH_2 on top of the LCOH of fossil-based hydrogen. Still, even with this, low-carbon fuels can be produced as of 2030 at around EUR 3.3/kgH_2 (see figure 4), which is below the current production cost of renewable hydrogen (around EUR 3.5–5/kgH_2[11]).

9 Directive 2023/2413 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources

10 Directive 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive 2023/1791 and repealing Directive 2009/73/EC

11 See Deloitte's analysis (Deloitte for Agora Energiewende and Agora Industry 2024) and Agora Industry EU map of hydrogen production costs (https://www.agora-industry.org/data-tools/agoras-eu-map-of-hydrogen-production-costs)

Breakdown of fossil gas-based hydrogen costs in Europe (SMR with 90% CCS) and average gas price of EUR 25/MWh * → Fig. 4



Deloitte for Agora Energiewende and Agora Industry (2024). Notes: *Baseline gas prices of EUR 33/MWh in 2030, EUR 25/MWh in 2040 and EUR 22/MWh in 2050. **The range of CO_2 storage and transport costs sees at the lower end onsite and onshore storage, at the higher end of the cost range offshore storage. The costs also vary from country to country, primarily depending on the distance to the offshore storage location, thus far the only available option.

These figures reflect production costs in Europe. They include infrastructure costs in Europe (e.g., for CCS), but they do not reflect potential costs for best available technologies (BAT) in non-EU countries that supply fossil gas to Europe.

The picture furthermore varies across EU countries: Member States with large wind and solar endowments tend to have the lowest production costs for electrolytic hydrogen production (EUR 2.8–3.3/kgH_2 in 2030 for Norway, Portugal and Spain).[12] In countries like Belgium and Germany, a bigger role can be anticipated for fossil gas-based low- carbon hydrogen and renewable/low carbon imports on the precondition that the required CCS and hydrogen transport infrastructure are in place.

The modelling also shows that the EU Emissions Trading System (ETS) will hardly impact the cost of fossil- based low-carbon fuels. An ETS price of EUR 200/tCO_2eq would add just EUR 0.20/kgH_2 (and, until the Carbon Border Adjustment Mechanism, or CBAM, kicks in only for CO_2 emissions within the EU). Methane emissions are currently not priced in the EU.

Hydrogen production costs of potential international suppliers[13] would be 28–40 percent below average EU LCOH in 2030 and 20–44 percent below in 2050, according to the modelling (see Figure 5). This does not factor in investment abroad necessary to reach BAT[14]. Even adding transport costs (EUR 0.1–0.3/kgH_2 for pipeline and EUR 1.3–1.6/kgH_2 for more complex logistical chains involving shipping and conversions[15]), importing from outside the EU could compete with unsubsidised production in Europe and thus be an attractive option particulary in the short to medium term.

12 Deloitte for Agora Energiewende and Agora Industry 2024

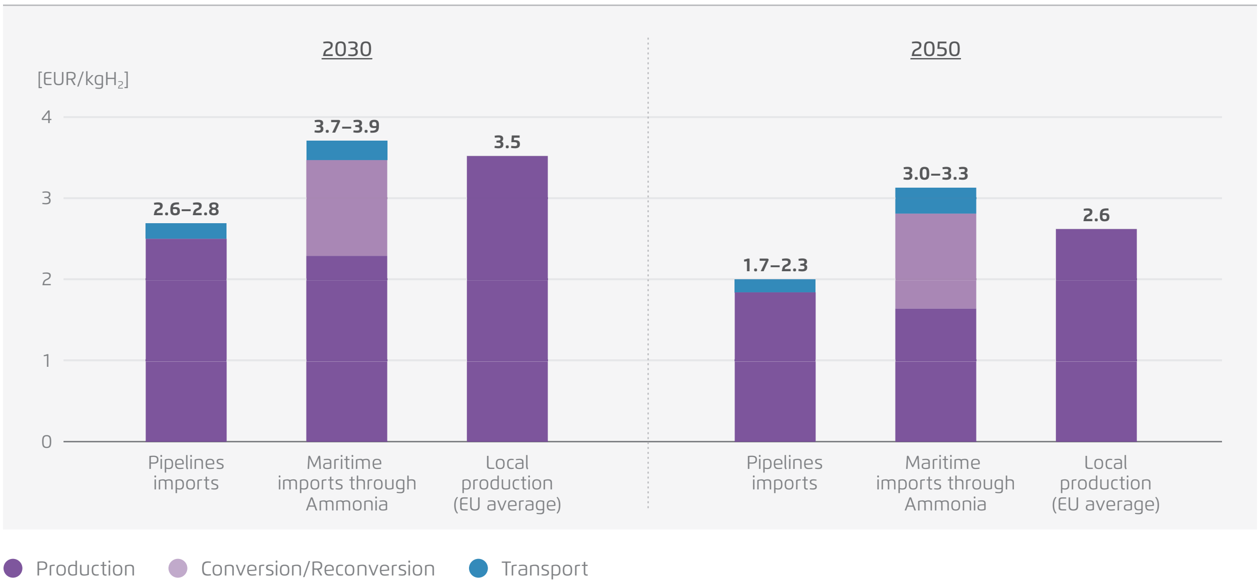
13 Assuming a mix of green and low carbon from imports as in the modelling outcome of Deloitte.

14 Deloitte for Agora Energiewende and Agora Industry 2024

15 Deloitte for Agora Energiewende and Agora Industry 2024

Comparison of landed cost of hydrogen* supply in Europe for pipelines and maritime imports and local production

→ Fig. 5



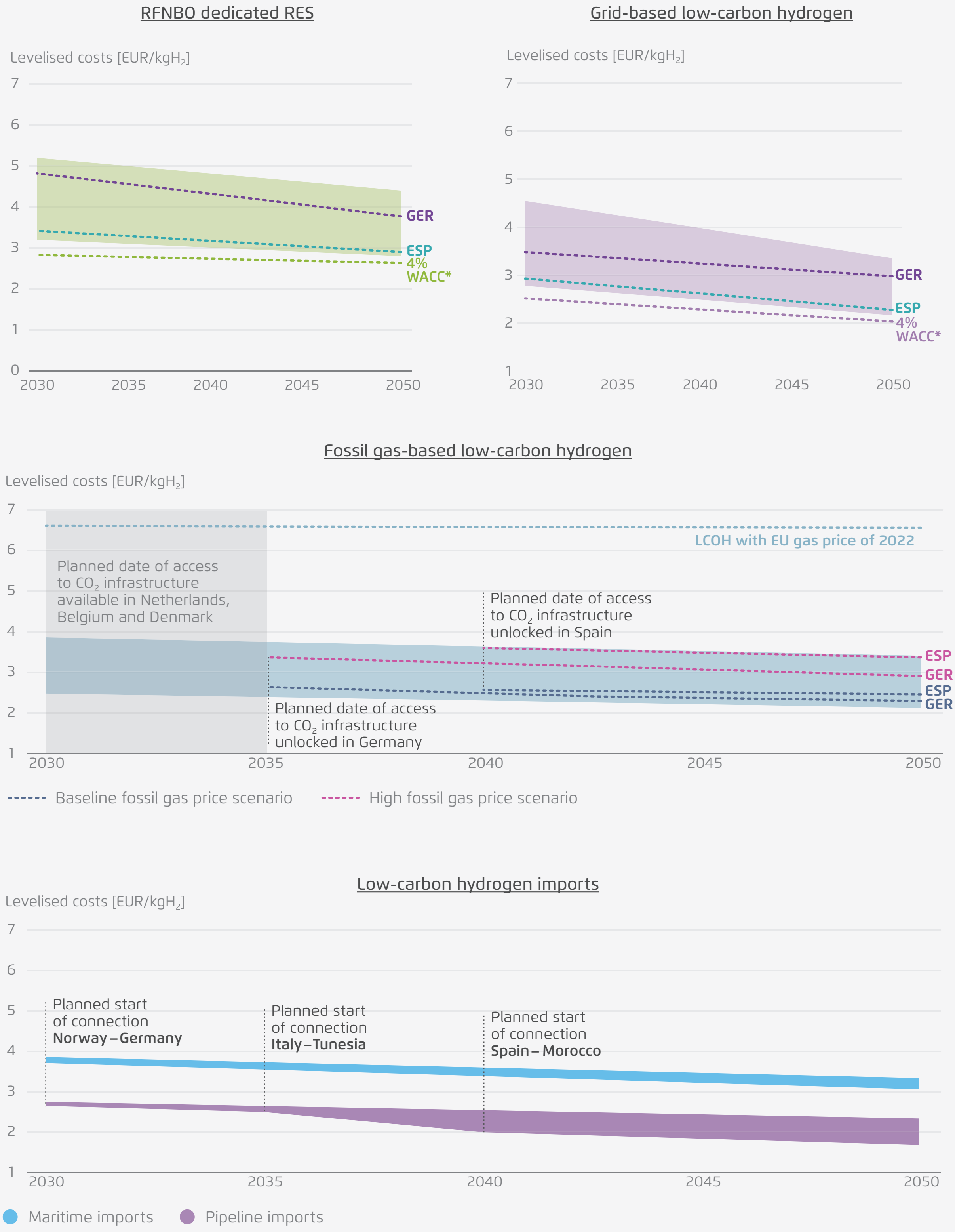
Deloitte for Agora Energiewende and Agora Industry (2024). Notes: *Mix of both renewable and low-carbon hydrogen reflecting the outcome of the modelling. See Deloitte (2024) for Agora Energiewende for more information.

After 2035, the share of solar photovoltaic (PV) and wind energy in the EU's electricity mix should allow grid-connected electrolysers to run 24/7 while producing RFNBOs or low-carbon hydrogen. This process can be accelerated by accounting closely for the actual emissions of production. With more and more electrolysers shifting to RFNBO production, the share of LCOH-related imports will also go down.

However, throughout the next two decades, the costs of renewable hydrogen will be at the higher end of fossil-based production costs with country-specific differences (see Figure 6). While renewable hydrogen produced in Spain will reach cost parity in around 2045, this would – depending on gas-price assumptions – not be the case for Germany.[16]

16 Assuming a gas- price range in the lower case of EUR 33/MWh in 2030 and EUR 22/MWh in 2050, and in the higher case of EUR 45/MWh in 2030 and EUR 35/MWh in 2050.

LCOH per supply route over time → Fig. 6



Deloitte for Agora Energiewende and Agora Industry (2024). Notes: Baseline gas price scenario with average gas price of 25 EUR/MWh until 2050, higher gas price assumes an average of 40 EUR/MWh until 2050. *The baseline WACC assumed is 6% for all EU27 countries. WACC could easily go down to 4% for mature technologies with a supportive policy/regulatory environments leading to low-risk perception for investors. The 4% WACC risks shown in the dotted line corresponds to RFNBO production in Southern Europe.

1.2 Life-cycle emissions of different hydrogen pathways

Renewable hydrogen is associated with zero greenhouse gas emissions under current EU rules, although from a life-cycle emissions perspective renewable hydrogen may come with "embodied" emissions that stem from the manufacturing of the necessary equipment (e.g., solar PV, wind turbines and batteries for storage). However, based on International Energy Agency data, embodied emissions of renewable hydrogen are well below the threshold of 3.38 $kgCO_2eq/kgH_2$ with 1.35 $kgCO_2eq/kgH_2$ for solar and 0.6 $kgCO_2eq/kgH_2$ for wind.[17] When moving towards stricter thresholds, more attention to embodied emissions (of solar) will be needed, although it is to be expected that the power mix underpinning solar module production will be getting less GHG intensive over time. At this point, embodied emissions are not accounted for in the EU's RFNBO methodology. However, they are also not accounted for as regards embodied emissions of biofuels and will probably also not be part of the low-carbon fuels methodology at this point in time.

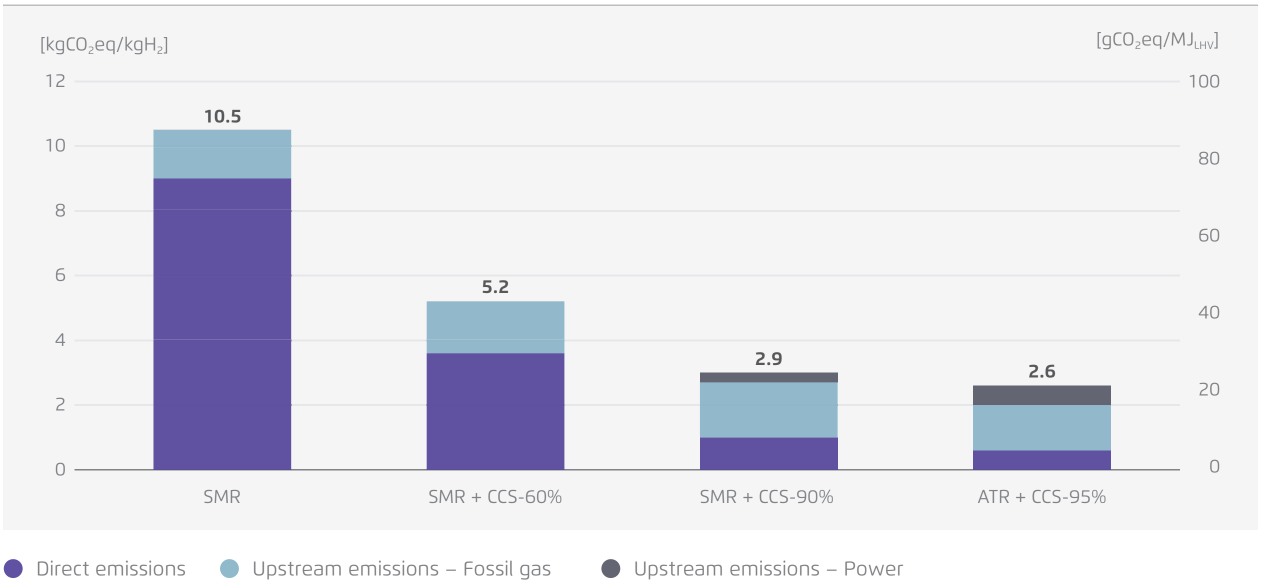
For gas-based pathways, leakage and combustion emissions play the dominant role (for biobased also the feedstock) and are much more significant in scale than embodied emissions of renewable production. Effective measures to tackle those emissions will determine whether or not fossil gas-based hydrogen can meet the 70 percent reduction criterion.

As shown in Figure 7, reforming with high CO_2 capture rates of above 90 percent combined with low upstream emissions trending towards zero can also deliver substantial reductions in order to get below the 70 percent threshold of 3.38 $kgCO_2eq/kgH_2$. This comes with higher electricity needs linked to the carbon capturing process in gas-based production in the range of 1–2 $kWhe/kgH_2$[18]

17 Comparison of the emissions intensity of different hydrogen production routes, 2021 – Charts – Data & Statistics - IEA

18 2 $kWhe/kgH_2$ translates into 0.6 $kgCO_2eq/kgH_2$ assuming the 2022 average EU grid emission intensity. Source: Deloitte for Agora Energiewende and Agora Industry 2024.

Carbon intensity of different fossil gas-based hydrogen production routes using the default emissions factor of 9.7 gCO_2eq/MJ → Fig. 7



Deloitte for Agora Energiewende and Agora Industry (2024).

Considering Europe's commitment to reach climate neutrality by latest 2050, fossil-based low-carbon hydrogen and renewable hydrogen should come with the lowest possible emissions, including consider-ation of embedded emissions, by that time. Against this background, the modelling done for this project suggests a gradual lowering of the GHG-intensity threshold down to around 1 $kgCO_2eq/kgH_2$ towards 2050. In that context, other impacts (health, water, land use, and, most importantly, hydrogen leakage, which is not included in the GHG accounting for this study) of hydrogen production should also be considered.

An often-overlooked aspect of hydrogen emissions accounting is that its GHG performance depends on the fossil fuel it replaces, as well as its use case. In fact, with the same 70 percent reduction threshold applied, 1 MWh of hydrogen that replaces 1 MWh of gas-based SMR results in 66 percent GHG eq saved, whilst it yields only 55 percent GHG eq savings if it is replacing gas used for heating[19]. Blending hydrogen into the gas grid is therefore not an effective use of hydrogen for decarbonisation (in addition to the cost and safety issues).

These considerations around use cases should not be understood as a plea for allowing different coun-terfactuals in the accounting methodology; indeed this would be difficult to report and verify. It rather seeks to underscore the point already made that EU and national hydrogen frameworks should ensure that hydrogen use is prioritised on applications where cheaper decarbonisation options – particularly through direct electrification – are not (yet) available.

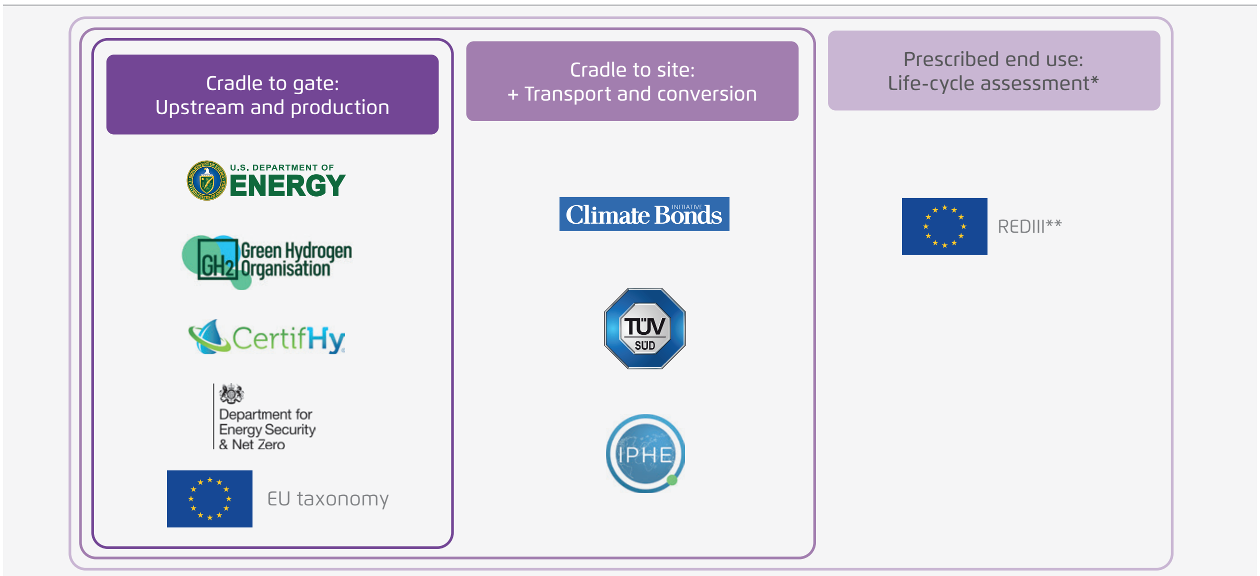
1.3 Existing standards and regulations for low-carbon fuel/hydrogen requirements

Elements of an emissions-intensity accounting methodology for low-carbon fuels/hydrogen appear in different pieces of EU legislation. Whilst the EU Hydrogen and Decarbonised Gas Markets Package contains a generic definition for low-carbon fuels, elements for accounting not fully renewable power are set out in the 2023 Commission delegated act on

19 Deloitte for Agora Energiewende and Agora Industry 2024.

Hydrogen standards system boundaries

→ Fig. 8



Agora Energiewende and Agora Industry (2024). Note: * Excluding embodied emissions from plant manufacturing. ** Green Hydrogen Organisation and RED III refer to renewable hydrogen only.

a GHG methodology for RFNBOs and RCFs. Other relevant pieces of legislation are the EU Methane Regulation[20] and the Carbon Capture and Storage Directive[21], with neither having quantitative performance requirements.

The Renewable Energy Directive and the EU Hydrogen and Decarbonised Gas Market Directive establish an at least 70 percent reduction against the liquid fossil fuel comparator of 94 gCO_2eq/MJ (or 3.38 $kgCO_2/kgH_2$ in a life-cycle assessment)[22] for all pathways, whilst renewable hydrogen rules spell out additional criteria for system friendly operation. The challenge will be to adopt similarly effective rules for carbon-based production as was done for fully renewable production.[23] The liquid fuel comparator implies a potential overestimation of the emissions reduction of gaseous fuels, however. Notably, in the 2023 GHG methodology delegated act, the default gas GHG value is the lower 66 gCO_2eq/MJ.

The EU Gas Directive calls for at least 70 percent reduction and tighter requirements for low-carbon fuels by 1 January 2031.

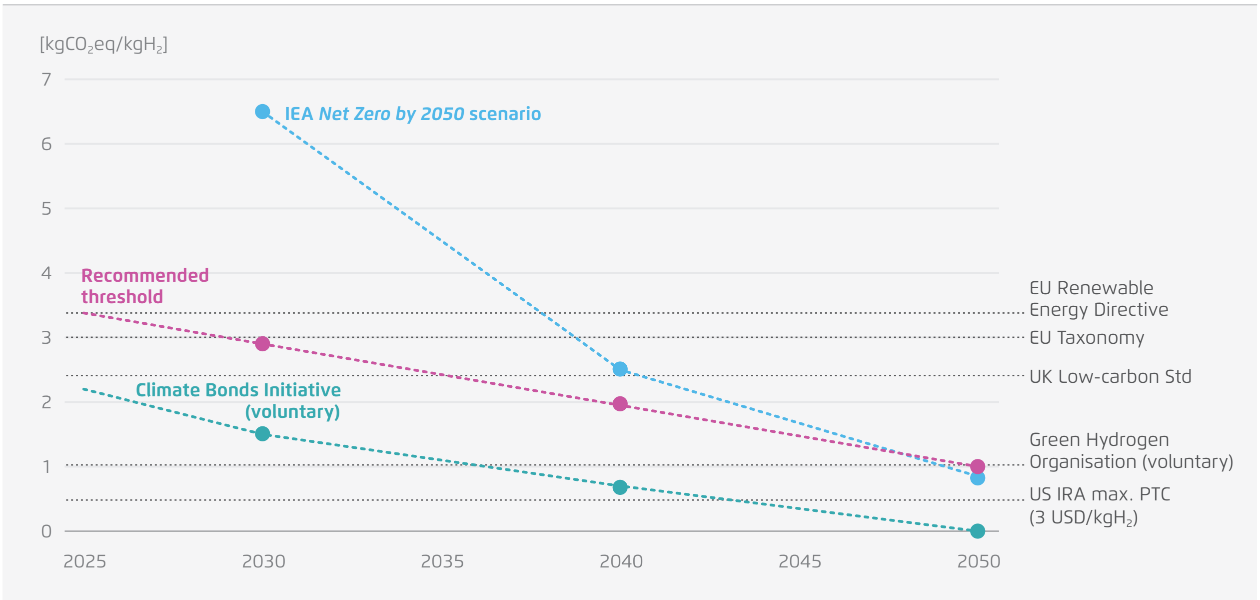
Other standards include the EU taxonomy with 3 $kgCO_2/kgH_2$ as well as the UK low-carbon standard with 2.4 $kgCO_2/kgH_2$ – both more demanding than the 70 percent requirement (3.38 $kgCO_2/kgH_2$), but not covering end use emissions, (see figure 8). Under the US Inflation Reduction Act, hydrogen production must stay below 0.45 $kgCO_2/kgH_2$ to tap the highest

20 Regulation 2024/1787 on the reduction of methane emissions in the energy sector and amending Regulation 2019/942
21 Directive 2009/31/EC on the geological storage of carbon dioxide
22 Considering that the energy content of the RFNBO is derived from renewable power only (i.e. zero carbon intensity), the 70 percent savings requirement represents also a limit for the carbon intensity of the non-renewable electricity feeding an electrolyser producing "low-carbon" hydrogen.

23 The EU's rules for RFNBOs stipulate as the main principle that the output from an electrolyser connected to the grid is an RFNBO only if produced from additional renewables underpinned by a PPA and that the electrolyser operation is locationally and temporarily matched to the generation from renewable electricity. The renewables capacity may not be supported financially. The output is also fully renewable if it is directly connected, happens in a grid with at least 90 percent share of RES, grid carbon intensity below 18gCO_2/MJ or in events of downward dispatch of RES.

Recommended dynamic threshold for the GHG intensity of hydrogen

→ Fig. 9



Agora Energiewende and Agora Industry (2024). Notes: The system boundaries and implementation details of these standards and requirements differ (see figure 8). The numbers for 2030 and 2040 have been rounded in the text accompanying this figure. The exact numbers used in Deloitte's modeling are 2.90 (2030) and 1.95 (2040) $kgCO_2eq/kgH_2$.

production tax credit (under a well-to-gate assessment). Voluntary standards include the Green Hydrogen Organisation's with 1 kg CO_2/kgH_2, which explicitly targets only renewable hydrogen production.

Hydrogen is an important element in climate-neutrality scenarios. As a result, the potential contribution of low-carbon hydrogen to net-zero ambitions needs to be evaluated against its greenhouse gas emissions intensity. To be in line with the IEA's Net Zero by 2050 scenario, hydrogen production should come with emissions of around 2.5 kgCO_2eq/kgH_2 by 2040 and 1 kgCO_2eq/kgH_2 by 2050 (figure 9). Most of the existing low-carbon hydrogen standards and legal requirements around the world are, however, static and therefore incompatible with this pathway in a 2040/2050 perspective. One notable exception is the voluntary Climate Bonds Initiative, which aims to mobilise sustainable finance towards truly net-zero compatible projects. It starts at 3 kgCO_2eq/kgH_2 and diminishes to 1.5 (2030) and 0.7 (2040) before reaching 0 kgCO_2eq/kgH_2 by 2050.[24]

To be aligned with the EU's binding target of climate neutrality by latest 2050, the EU should set from the start a dynamically decreasing maximum greenhouse gas threshold for low-carbon fuels, starting with 3.38 kgCO_2eq/kgH_2 (the current threshold) to reach 3 kg (referred to in the EU taxonomy) by 2030, 2 kg by 2040 and 1 kg by 2050.

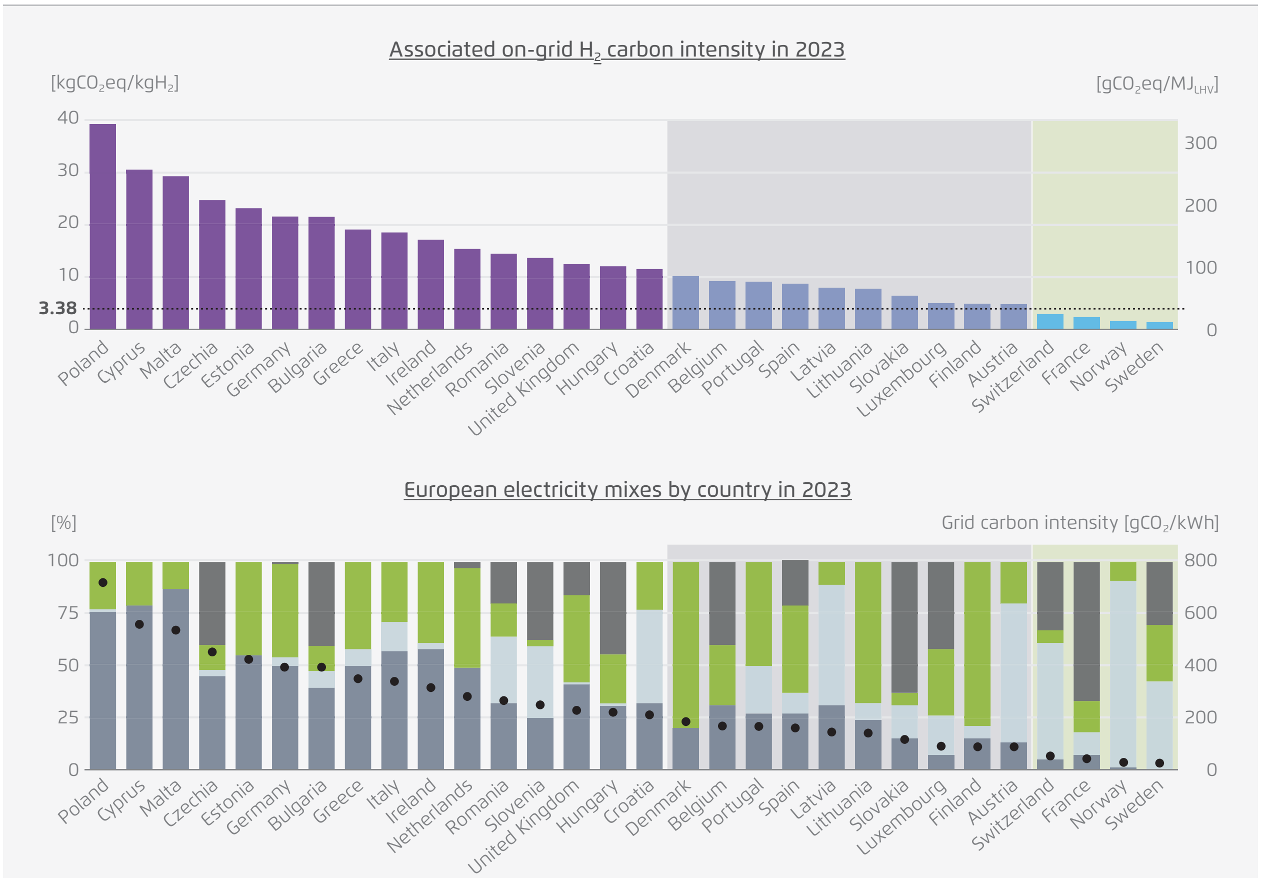
24 CBI (2023): Hydrogen Criteria Background Paper ; FCHEA (2022): How the Inflation Reduction Act of 2022 Will Advance a U.S. Hydrogen Economy

2 Ensuring that grid-based hydrogen is low carbon and allows for renewable hydrogen to compete on fair terms

Using electricity to produce hydrogen, hydrogen derivatives and e-fuels has an efficiency of 38–55 percent[25] depending on the number of conversion stages involved. This implies that the emission intensity of the input electricity should be multiplied by a factor of two to three to arrive at the specific emission intensity of the produced hydrogen. It is this multiplier effect that can result in grid-based hydrogen being more GHG intensive than the use of unabated fossil fuels, unless rules are in place that ensure electrolysers operate mainly in hours with low emissions in the grid.

25 cf. Agora Industry and TU Hamburg (2023)

Current European electricity mixes and associated H_2 carbon intensity for an electrolyser based on constant output → Fig. 10



Deloitte for Agora Energiewende and Agora Industry (2024).

Running an electrolyser 24 hours a day, seven days a week during the entire year currently means that in 15 EU Member States emissions will exceed those of unabated fossil hydrogen; in 10 EU Member States emissions would be below the 11.3 $kgCO_2eq/kgH_2$ fossil-fuel reference but still above the necessary 3.38 $kgCO_2eq/kgH_2$ threshold.

In order to avoid pushing up the marginal high-emitting emissions in a system with scarce supply (and by extension also prices for households and industry as the marginal fossil units are costlier), the renewable-hydrogen rules demand additionality and system-friendly operation keeping grid bottleneck and real-time power production in mind[26]. This is justifiable as producers enjoy the RFNBO label and the green premium (and/or public funding) that comes with it.

Since it is irrelevant for the grid (emission intensity) whether the marginal unit is used for producing renewable electrolytic hydrogen or low-carbon electrolytic hydrogen, similar framing conditions for low-carbon fuels and for RFNBOs seem necessary to ensure that a future low-carbon fuel label is credible. This will also be needed so that renewable hydrogen can compete on equal terms and that the share of renewables in the system scales up quickly (which in return will allow for a better business case for electrolysers partly producing low carbon).

Having said that, it is difficult to apply the concept of additionality to the production of low-carbon grid-based hydrogen. Clearly, as regards low-carbon hydrogen, the most important aspect is accurate accounting of actual GHG emissions (see section 2.1 below). However, because low-carbon hydrogen producers will benefit from public investments into wind and solar, which allow the grid to become cleaner and reduce the costs of producing low-carbon hydrogen (due to increasing operating hours of electrolysers), the EU could consider a mandatory contribution of low-carbon hydrogen producers into the EU Renewable Energy Financing Mechanism. It should also be noted that draft hydrogen standards in the US apply incrementality to all production pathways, not only renewables-based ones.

Some stakeholders have suggested that it should not be allowed that fossil gas used to produce low-carbon fuels would come from new fossil-fuel exploration. Whilst such a requirement cannot be based on the delegated authority of the Commission under the Gas Directive, it could conceivably be derived from the EU climate law.[27]

To ensure that grid-based hydrogen is low-carbon and allows for renewable hydrogen to compete on fair terms, the following two conditions should be fulfilled: ensuring real-time GHG profiles rather than annual averages for electricity accounting or low-carbon power-purchasing agreements (PPAs) and avoiding double counting of the renewables content of contracted PPAs in countries' power mix.

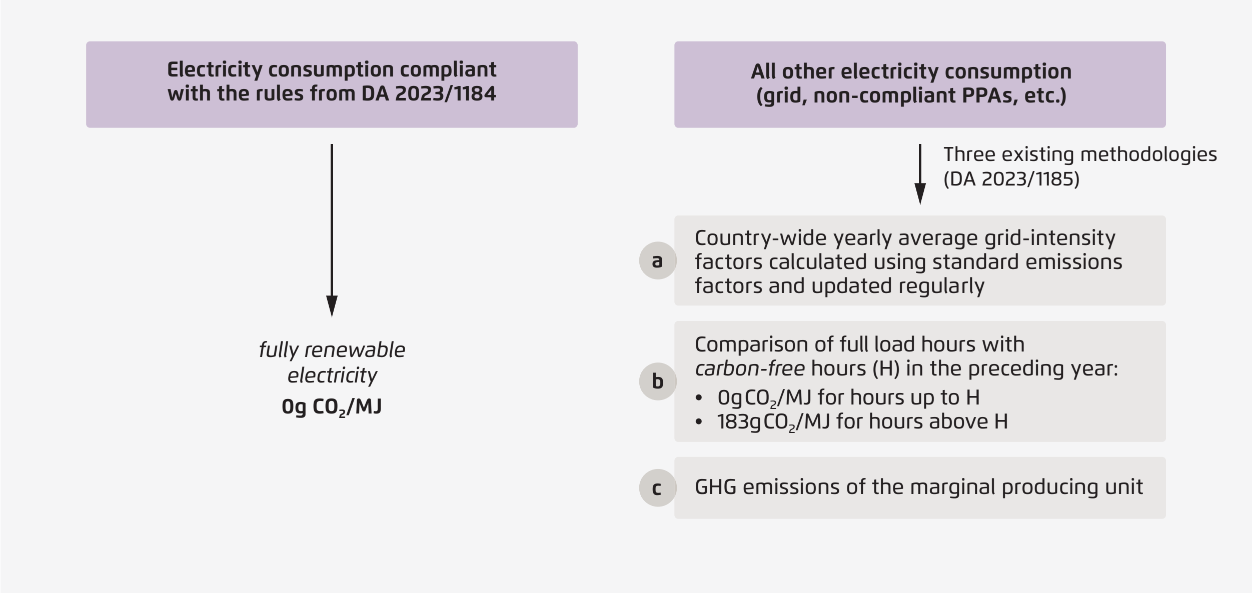
2.1 Ensuring GHG accounting reports the specific power sector emissions related to hydrogen production

Using the emission intensity of the actually consumed electricity mix of an installation (rather than averages or default values) is necessary for a low-carbon label to be trustworthy – as otherwise hydrogen could in fact be produced with very high emissions. Not all allowed GHG accounting options for not fully renewable electricity set out in the 2023 GHG methodology for RFNBOs and RCFs are suitable to this end.

26 The latter suggests that the current system of guarantees of origin for electricity should become more granular; this would also be highly conducive to rewarding storage and power system flexibility.

27 cf: 2024.04.02-Joint-letter-low-carbon-hydrogen-definition.pdf (renewableh2.eu). .

GHG accounting methodologies from the RFNBO's delegated act → Fig. 11



Agora Energiewende and Agora Industry (2024) based on a similar illustration from Deloitte (2024).

Figure 11 illustrates three methods available. Method a) is based on average grid-emission intensity, method b) on full-load hours and method c) on emissions of the marginal unit in a certain hour.

→ Method a) provides no incentive to switch off an electrolyser when the share of fossil-based electricity in the system is high and will therefore deliver only a rough approximation of the real GHG footprint of the produced hydrogen[28].
→ Method b) would also not encourage system-friendly operation as it uses only two emission values for accounting. However, it does come with an implicit cap on maximum operating hours of high emissions and, as a result, constitutes an improvement compared with method a).
→ Method c) on the other hand captures the actual GHG emissions accurately. It forces producers to monitor real-time grid status and to run the electrolyser only when the grid is (almost) fully decarbonised.

28 The standard emission factors approach would incentivize maximum running hours in countries with-low carbon mixes, whilst other countries are prevented from producing grid-based low-carbon hydrogen in the beginning.

The modelling underpinning this report shows that using method c) rather than a) would result in additional accumulated greenhouse gas emissions savings of 29 $MtCO_2eq$ until 2050. The use of method c) would furthermore boost the upscaling of electrolysers in the EU with one-third more installed capacity by 2030 compared with method a) by encouraging a faster cleaning up of the grid.

In order to provide the same level of regulatory ambition as for renewable hydrogen with regard to temporal and geographical matching and to make sure that grid-based low-carbon hydrogen or e-fuels are indeed low in emissions, method c (at hourly intervals and at bidding zone level) of the 2023 delegated act should be the only method admitted for low-carbon accounting. This should be the case at the latest in 2030 when hourly matching applies for renewable hydrogen.

It is assumed that the low-carbon accounting methodology does not allow for PPAs, a specificity in the fully renewable-hydrogen route. If contracting existing low-carbon electricity were allowed, this would again deviate from actual emission accounting and create a significant disadvantage for renewable hydrogen that has to contract new and also non-supported renewable electricity.

2.2 Avoiding double counting of renewables under PPAs in the reference power mix

It is important to avoid double counting of renewables in the power mix, once for RFNBO production under PPAs and once for calculating the average emission intensity of electricity used for producing low-carbon hydrogen. The share of electricity used for RFNBO production represents an average of 3 percent in Europe both in the short term and long term, with a variation across countries from 1 percent (in Germany) to more than 5 percent (in Belgium). Double counting the renewable electricity sold through PPAs for RFNBO production would not only result in a higher share of renewable electricity in the overall mix to determine the shares of low-carbon production, it would also decrease the average carbon content of the power mix by 4 gCO_2eq/kWh in 2030 and by 0.3 gCO_2eq/kWh in 2050.[29] The size of double counting would reach 0.7 Mt annually in 2050 in Europe if not corrected in the accounting methodology for low-carbon fuels.

29 The highest values are observed for Poland and Belgium, decreasing 12 and 10 gCO_2eq/kWh in 2030 respectively. Yet, in the modelling framework of this study, this reduction does not bring the yearly average of any EU country below the threshold.

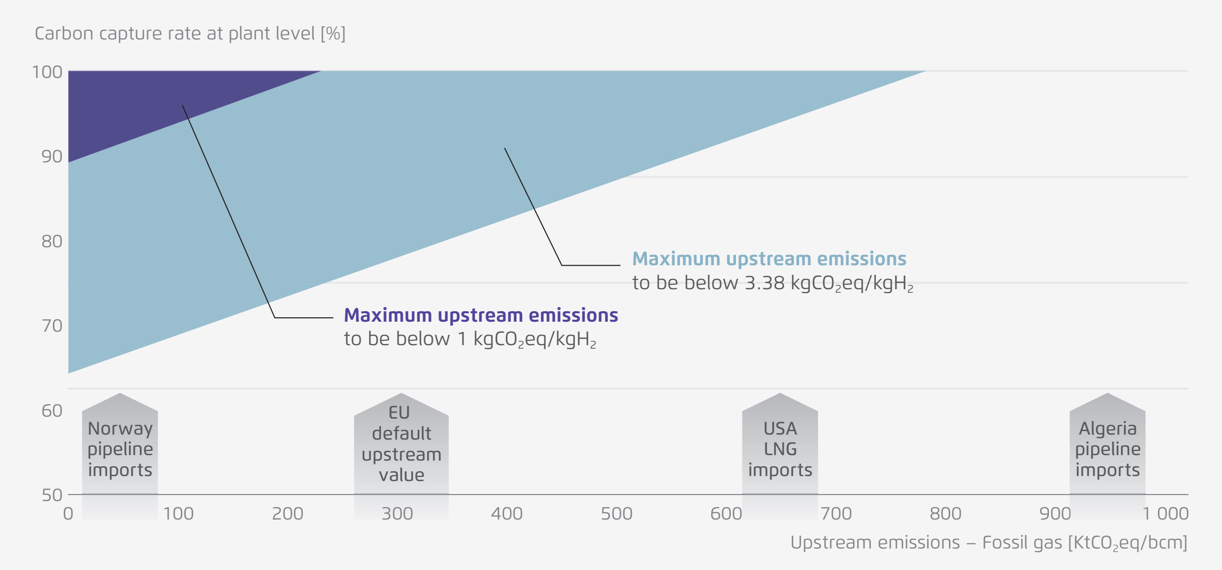
3 Ensuring that fossil-based hydrogen contributes to reducing GHG emissions

Three pillars are necessary to ensure gas-based fuels are sufficiently low carbon: Controlling upstream emissions (mainly methane, but also CO_2), getting to high-performant carbon capture and ensuring permanent storage of captured carbon.

Generally, it can be observed that upstream methane-leakage rates differ considerably from country to country and even within countries (ranging from close to zero to above 3 percent), whilst carbon capture performance during hydrogen production is currently similar across regions. Whether performances for both main emission sources improve sufficiently to meet the thresholds set in the low-carbon fuels standard will have to be continuously monitored.

The performance rates for controlling upstream leakage of both methane and CO_2 and of capturing carbon at the point of hydrogen production will – in combination – determine the emission intensity of the produced hydrogen; both can be used to improve the carbon footprint through possible combinations for meeting the 70 percent reduction (see figure 12). As can be seen, currently only Norway controls upstream leaks sufficiently to be able to pass the 70 percent threshold with the current carbon-capture systems. Other countries would need to get to above 90 percent capture efficiency to pass (in the case of the US) or cannot even pass without also addressing upstream leaks (Algeria). The UK can be expected to meet the EU requirements, also due to its own strict low-carbon standard.

Necessary CCS and upstream leakage performances to meet low-carbon emission intensity requirements → Fig. 12



Deloitte (2024) for Agora Energiewende based also on input from Carbon Limits.

3.1 Controlling upstream greenhouse gas emissions (methane and CO_2)

EU climate policies have traditionally focused on mitigating CO_2 emissions. However, with efforts to keep the goal of limiting warming to well below 2 degrees Celsius at a critical point, efforts to control methane emissions have moved to the fore as methane has a much higher short-term warming potential compared with CO_2.[30] Even small methane-leakage rates during fossil-gas production can cancel out the climate-mitigation potential of fossil gas-based hydrogen.[31]

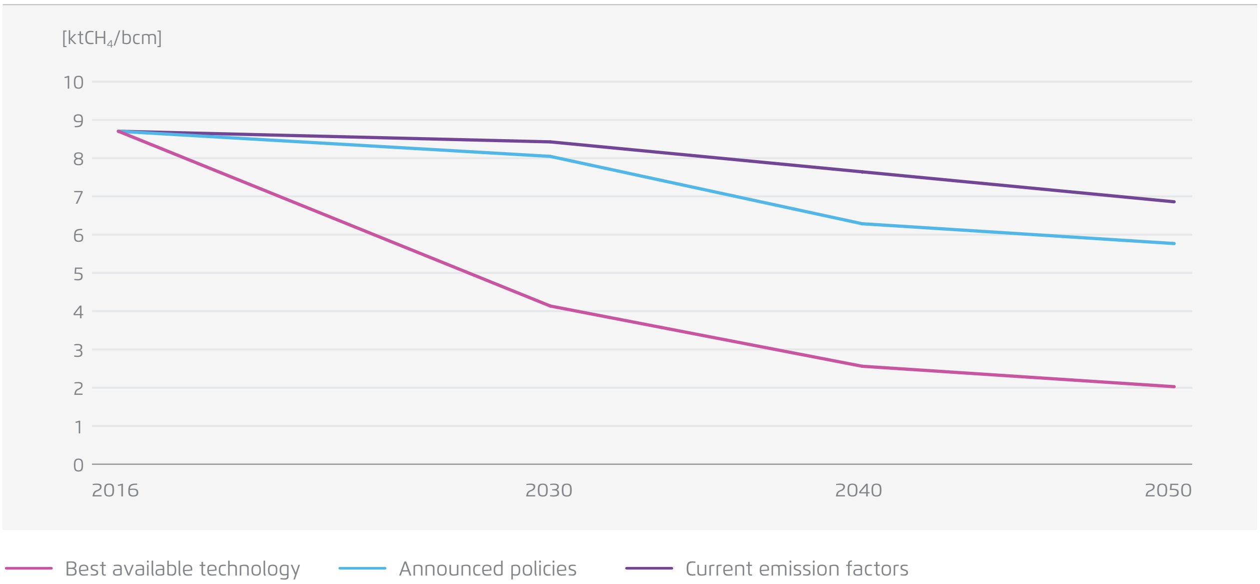
Gas suppliers to Europe today have upstream leakage rates ranging between close to 0 to above 3 percent (meaning between 0 to above 20 $ktCH_4$/bcm) depending on the fossil-gas source and existing practices to contain methane leakage. However, there are also differences within countries (e.g., from basin to basin such as in the US).[32] Methane leakage accounting for liquefied natural gas (LNG) complicates the picture even further as part of the leakage control value chain happens on ships and involves a different set of stakeholders.[33]

Accounting for upstream emissions properly as part of calculating life-cycle carbon intensities is therefore crucial. The uniform default upstream emission factor of 9.7 g CO_2eq/MJ[34] in the 2023 delegated act on the GHG methodology for RFNBOs and RCFs seems inadequate. It reflects default emissions of pipeline gas from Russia and – as becomes apparent from figure 13 - does not encourage implementing cost-effective measures to reduce methane leakage. Worse, some fossil-gas trading partners of the EU show higher leakage rates than the default value as shown in figure 14.

30 Methane has a shorter atmospheric lifetime than carbon dioxide, but a very high warming potential, which makes it 84 times more potent as a greenhouse gas over a 20 year period compared to CO_2.
31 Agora Energiewende (2021): 12 insights on hydrogen

32 EPA Data Show Across-the-Board Drops in Total Methane Emissions in Top Oil, Natural Gas Producing Basins (eidclimate.org). EPA Data Show Across-the-Board Drops in Total Methane Emissions in Top Oil, Natural Gas Producing Basins (eidclimate.org).
33 Total Methane and CO_2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements - PMC (nih.gov)
34 It is not clear whether this default value captures only upstream methane emissions or also upstream CO_2 emissions.

Methane emissions in Europe currently, with announced policies and compared to what could be abated under BAT → Fig. 13



Shirizadeh, B., Villavicencio, M., Douguet, S. et al. (2023).

Applying the above-mentioned uniform default emission factor indiscriminately could underestimate real-world emissions from fossil-based hydrogen by a factor of 2.5 for Europe by 2040.[35] The default emissions factor should therefore be complemented by country-specific, preferably basin-specific, emissions factors until site-specific rules kick in under the EU Methane Regulation.

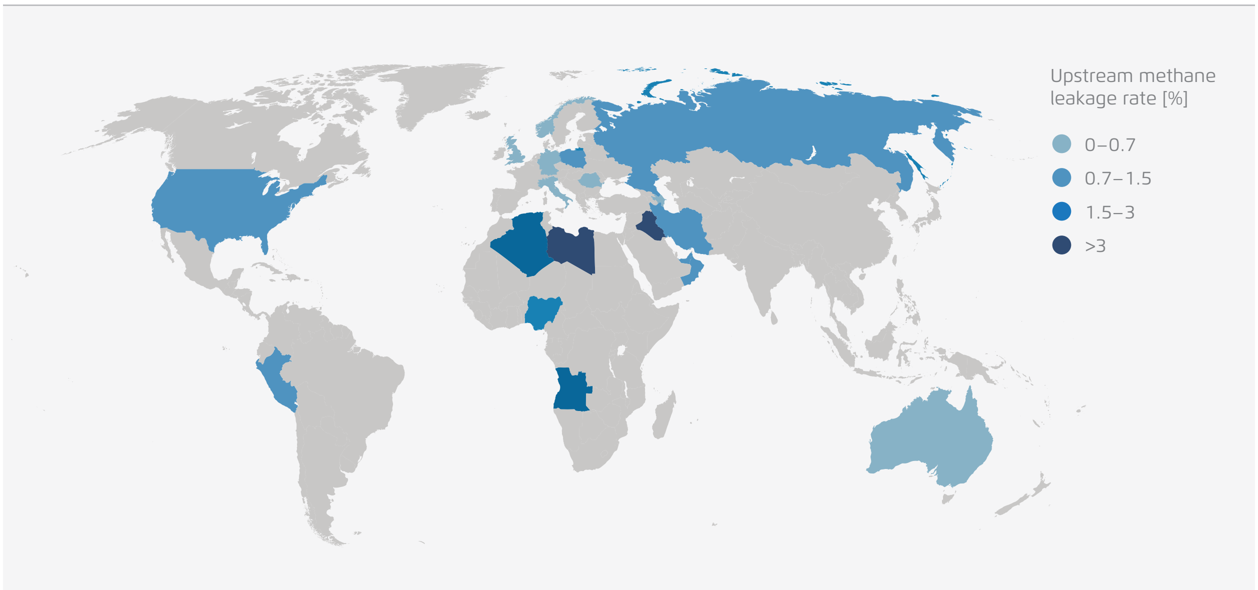
However, methane emissions are not the only upstream emissions relevant in the low-carbon fuels value chain. Upstream emissions of CO_2 are still substantial despite years of regulatory attention. Currently more than half of the entire life-cycle CO_2 emissions of fossil gas from Algeria that is then used to produce low-carbon hydrogen in Germany with CCS technology would result from upstream CO_2 emissions in Algeria as well as emissions from transportation and storage.[36]

This shows that fossil-gas suppliers such as Algeria, Nigeria and the US with significant upstream emissions would need to deploy short-, medium- and long-term abatement measures to be able to supply fossil gas to Europe that could be used for producing low-carbon hydrogen. Progressively implementing BAT would enable more gas-exporting countries to meet the low-carbon emission-intensity threshold set out in the future Delegated Act. What is the appropriate mix of best available technologies and relevant behavioural measures to abate methane and CO_2 will vary from country to country. Box 2 provides a selection of important technologies and behavioural measures.

However, in the context of this analysis an important insight is that, without sustained efforts towards implementing BAT, important fossil-gas supplier countries – like the US or Algeria – will not be able to meet the 70 percent reduction threshold.[37]

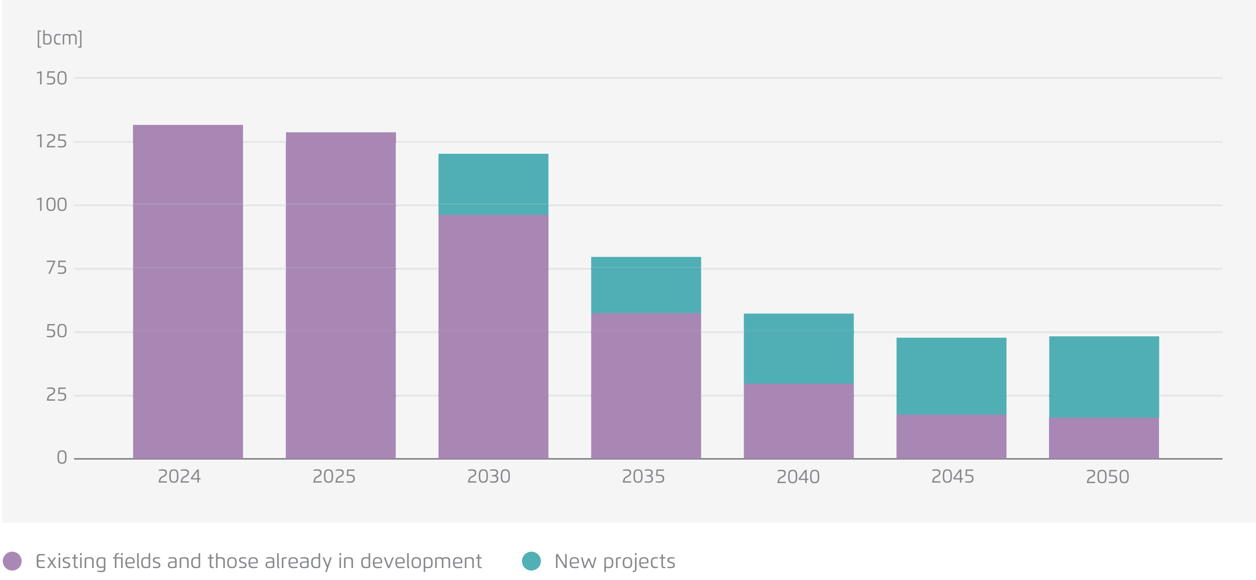
35 calculated by Deloitte for Agora Energiewende and Agora Industry 2024 based on BAU and BAT information provided by Carbon Limits.
36 Carbon Limits for Agora Energiewende and Agora Industry 2024
37 cf Carbon Limits for Agora Energiewende and Agora Industry 2024

Current methane leakage rates for key EU gas supplying countries → Fig. 14



Agora Energiewende (2024). https://www.hydrogen4eu.com/_files/ugd/2c85cf_e934420068d44268aac2ef0d65a01a66.pdf.

Projected fossil gas production in Norway → Fig. 15



Deloitte for Agora Energiewende and Agora Industry (2024).

At present, only fossil gas supplied by Norway could be used for producing low-carbon hydrogen in Europe. At the same time, projections are that Norwegian fossil-gas resources will decline even with investments into new exploration (see figure 15). If lack of effort to implement BAT were to reflect a broader trend, it **could see the EU becoming heavily reliant on very few fossil-gas suppliers in the future, with significant risk to Europe's future security of supply**.

In line with the Oil and Gas Methane Partnership (OGMP) Gold Standard (see box 3) and the recent EU Methane Regulation, producers should be obliged to ensure source and site-specific measurement, either with a stringent penalty scheme as under the EU Methane Regulation or independent verification of reported data.

Box 2: Main abatement options for methane and CO_2 along the fossil and biogas value chain

Abatement of methane

→ (Early) replacement of pumps, compressors, seals
→ Upgrading installed technology to instrument air systems and electric motors
→ Installation of vapor recovery units
→ Implementing leakage detection and repair along the value chain (also for biogas)
→ Waste heat recovery in hydrogen production and biogas/methane sites
→ Using renewable/low-carbon power in production sites
→ Optimizing manure storage sites and storage duration
→ Reducing the share of food and feed-based biogas feedstocks and prioritising residues and waste
→ Reducing methane slips in bioreactors, oxidization for residual methane

Abatement of CO_2

→ Route optimization for CO_2 transport
→ CCS on SMR/ATR and biogas point sources
→ CCS on acid recovery gas units
→ Use of excess gas for onsite processes instead of flaring
→ Heat recovery and electrification for the entire fossil and biogas value chain
→ Use of renewable/low-carbon energy onsite for processes rather than fossil fuels

For a complete overview: Carbon Limits (2024)[1]

1 Carbon Limits for Agora Energiewende and Agora Industry 2024

Box 3: The Oil and Gas Methane Partnership

The Oil and Gas Methane Partnership (OGMP) 2.0 is a voluntary global partnership led by UNEP and joined by oil and gas companies representing over 35 percent of the world's oil and gas production. Companies self-report annually their methane emissions according to a detailed and transparent reporting framework. OGMP verifies the reported emissions, but there is no independent auditing requirement otherwise. OGMP does not cover other GHG besides methane. Companies are also required to develop and submit a methane emissions reduction plan and a three-year roadmap detailing how they will reach this goal.

There are five levels of reporting within OGMP and the Gold Standard is achieved by meeting Level 4/5 reporting for operated assets within three years and for non-operated assets within five years (which imply moving away from only default emission factors to measurement). OGMP 2.0. is also the basis for the recently adopted EU Methane Regulation until the European Commission has adopted its own implementing acts detailing the methodology for reporting[1].

1 According to the EU Methane Regulation, operators will need to submit reports to the competent authorities containing:
→ Quantification of source-level methane emissions within 18 months for operated assets and within 30 months for non-operated assets.
→ Quantification of source-level methane emissions combined with site level measurement of emissions within 30 months for operated assets and within 48 months for non-operating assets.

3.2 Improving capture rates of CCS

CCS refers to the capture of CO_2 emissions from point sources such as industrial processes or from the use of fossil fuels. The CO_2 concentration of the emissions stream and the capture technology deployed have a large impact on actual capture rates. **Current capture rates for CCS amount to approximately 60 percent of the total CO_2 emissions occurring during hydrogen production.**[38] This represents what can be achieved using SMR for capturing emissions generated by the feedstock-related use of gas (synthetic gas). These emissions can be captured at a relatively low cost, but more is needed to achieve the 70 percent threshold of emission reductions. More advanced capture technologies (i.e. capturing the second CO_2 outlet, flue gas) could bring performance up to 90 percent but are not yet deployed and would come at higher cost.

Notably, innovative pre-combustion methods are deemed capable of achieving a 95 percent capture rate with SMR, but this has yet to be achieved in actual operations. For example ATR, which is currently technology readiness level (TLR) 5 in the IEA Global Hydrogen Review[39], has only one and more concentrated CO_2 stream that can lead to higher capture rates. According to the IEA, two sites with above 95 percent ATR capture are currently planned in the US.

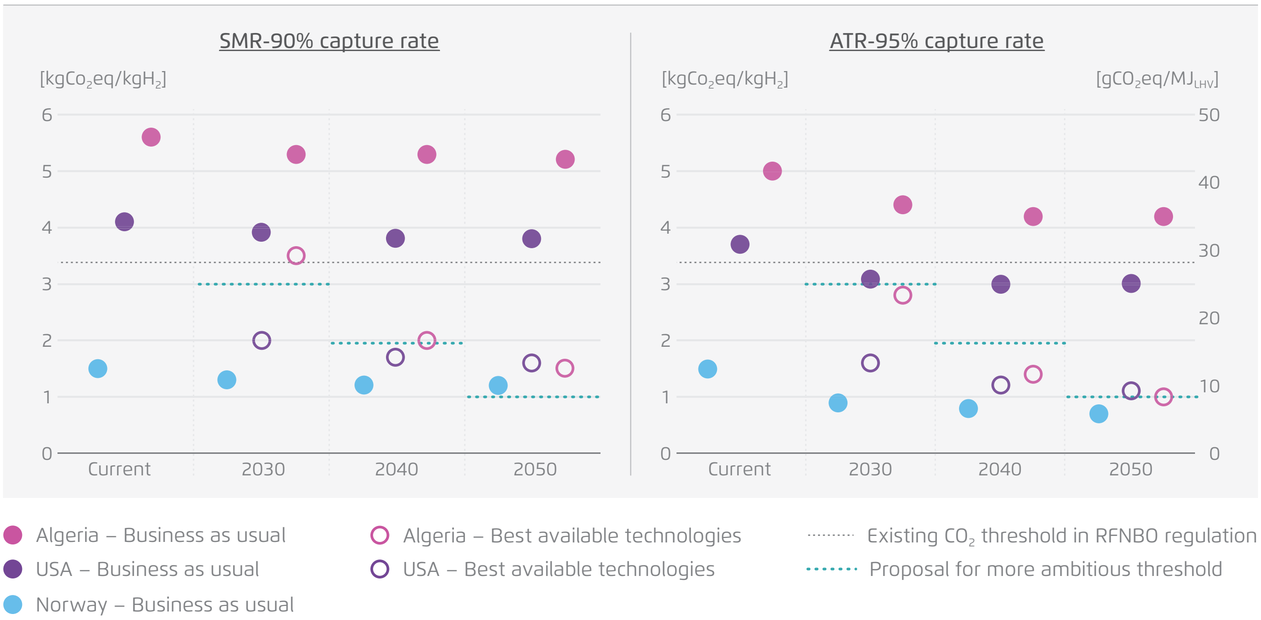
Assuming the current EU fossil-gas default emission as demonstrated in figure 12 **allows both SMR and ATR with 90 percent CCS performance to pass the EU threshold.** Whilst 90 percent might sound like a lot, it still leaves considerable emissions that need to be compensated for with negative emissions and policies should therefore be encouraging capture rates well above 95 percent. In this context, it is noteworthy that the EU CCS Directive[40] does not set minimum-performance requirements.

38 ICCT (2021) : Life-cycle greenhouse gas emissions of biomethane and hydrogen pathways in the European Union and IEA (2023).

39 IEA (2023)

40 DIRECTIVE 2009/31/EC on the geological storage of carbon dioxide

Carbon footprint of fossil gas-based hydrogen produced in Germany as a function of fossil gas origin → Fig. 16



Carbon Limits for Agora Energiewende and Agora Industry (2024).

In order to provide an incentive for rapid deployment of the higher performant CCS systems, it would seem useful to set a dynamically decreasing maximum GHG threshold for low-carbon fuels, starting with the current threshold of 3.38 kg CO_2eq/kgH_2 and declining to 3 kg (referred to in the EU taxonomy) by 2030, to 2 kg by 2040 and to 1 kg by 2050.[41] **A static threshold bears the risk that efforts to go significantly beyond the 70 percent reduction are not undertaken.**

3.3 Ensuring permanent CO_2 storage

Lastly, greenhouse gas emissions savings from producing fossil-based hydrogen with carbon capture are accountable as savings only if the CO_2 does not get back into the atmosphere at some point. For this reason, CCS laws such as the EU's CCS Directive and the Californian CCS Protocol for the Low Carbon Fuel Standard[42] require that CO_2 captured from fossil operations is stored "permanently" (EU) or for "at least 100 years" (California) and refers to geological storage as the only option, as does the Delegated Act on the GHG methodology for RFNBOs and RCFs.

The recently adopted EU Net Zero Industry Act[43] sets the target to create – by 2030 – 50 Mt CO_2 annual injection capacity of geological storage. The delegated act for low-carbon fuels should be designed as facilitating this ambition by maximising CCS over CCU wherever possible.

While geological storage of captured CO2 seems mainly a challenge of costs and technical availability, broadening the scope to Carbon Capture and Use applications (CCU) would add layers of complexity when it comes to verification and certification of an already long value chain if use case and duration are to be verified. CCU should in our view therefore be excluded from the scope of the low-carbon fuels methodology. Currently drafted rules under the ETS will probably allow for very limited CCU based on mineralisation to be exempt from the need to purchase ETS allowances. Whether this should then also be admissible for low-carbon fuels is a different question and can be answered only once all available carbon storage and removal opportunities are screened. Another technological option for using captured CO_2 that should be excluded under the carbon-emission accounting is "Enhanced Oil Recovery" (EOR) (for details see box 4).

41 cf Deloitte for Agora Energiewende and Agora Industry 2024
42 https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf
43 Regulation (EU) 2024/1735 on establishing a framework of measures for strengthening Europe's net-zero technology manufacturing ecosystem

Box 4: CO_2 use for enhanced oil recovery

Gas injection (amongst others through injecting CO_2) is currently the most used approach for enhanced oil recovery (EOR). Basically, fossil gas is used to extract more fossil oil. EOR therefore creates additional emissions compared to a typical CCS project and should not be an allowed use case:
On a life-cycle basis, only 63 percent of all CO_2 stored through EOR is a net reduction in CO_2 emissions (whilst CCS can lead to a net reduction above 90 percent). There is also a risk of double counting emission reductions related to EOR as it could be claimed by the hydrogen plant or the oil and gas company (Carbon Limits, 2024).

3.4 Other issues: Hydrogen emissions and global warming potential

Hydrogen is a leak-prone, short-lived indirect greenhouse gas that warms the climate by increasing the amounts of other greenhouse gases such as methane in the atmosphere. There is a broad scientific consensus on the warming potential of hydrogen emissions[44]. This consensus is reflected in, for example, the UK's low-carbon hydrogen standard. Hydrogen leakage can occur in various stages of production, storage and transport and in all production pathways, including renewable-based ones. However, at this stage there exists little information on actually measured hydrogen-leakage rates. A recent study[45] reports a 0.2–20 percent range across the value chain – a vast span that points to the need for strict monitoring. For the analysis underpinning this report, hydrogen leakage was not part of the GHG calculation and sensitivity testing in order to keep the project manageable. This implies that the real world climate impact of some of the analysed gas/hydrogen value chains will be larger than estimated in this report.

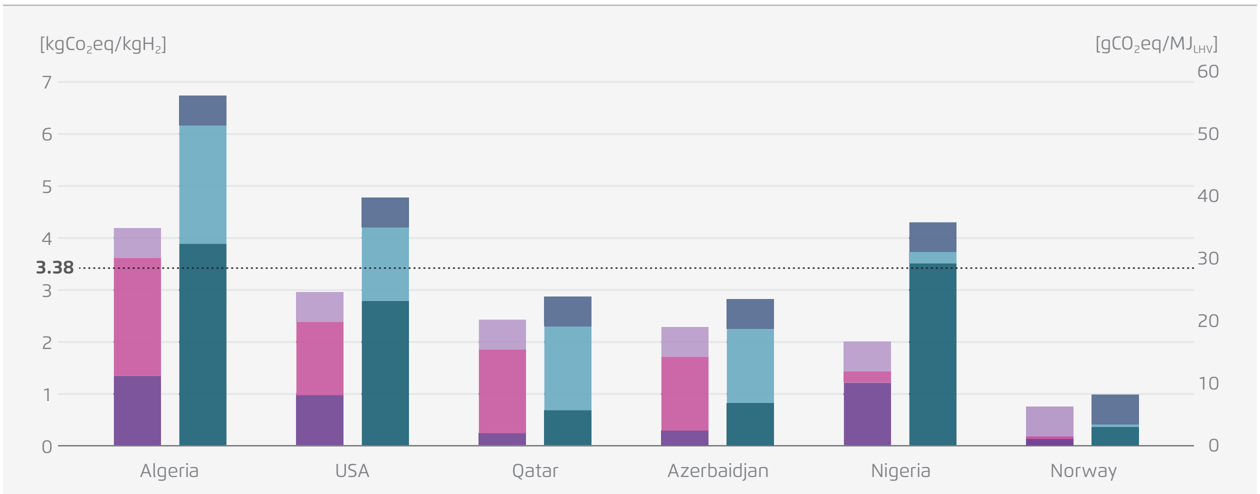
Hydrogen leakage is included in Art 9 (5) of the EU Gas Directive[46] as one of the elements to be considered for the low-carbon fuel methodology. However, the agreed text seems to propose a two-step approach with the Commission first coming out with a report and then, if appropriate, establishing maximum hydrogen-leakage rates. We recommend that the EU follow the example of the UK and establish from the start an obligation to employ BAT for hydrogen-leakage control as part of the low-carbon fuels accounting methodology. In parallel, the EU should seek to improve knowledge on the issue and prioritise funding for projects that use hydrogen on site (minimising leakage through transport) and/or with best-in-class methane-leakage abatement.

44 Latest science suggests that hydrogen emissions are 30–40 times more powerful at trapping heat over the following 20 years than carbon dioxide for equal mass, and 8–12 times more powerful over a 100- year period. (https://acp.copernicus.org/articles/23/13451/2023/acp-23-13451-2023.html)

45 https://www.frontiersin.org/journals/energy-research/articles/10.3389/fenrg.2023.1207208/full

46 Directive 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive 2023/1791 and repealing Directive 2009/73/EC

Hydrogen GHG footprint from ATR with 95% capture rate with current upstream emissions factors using different global warming potential assumptions → Fig. 17



GWP 100: Upstream methane leakage · Upstream CO_2 emissions · Direct emissions
GWP 20: Upstream methane leakage · Upstream CO_2 emissions · Direct emissions

Deloitte for Agora Energiewende and Agora Industry (2024).

It should also be noted that using a 100-year timeframe for assessing the impacts of methane, a short-lived climate gas, paints a more positive picture than if a global warming potential (GWP) of 20 years were used, as can be seen in figure 17.

Since the choice of GWP is outside the scope of the delegated act on low-carbon fuels, the other variables of the future low-carbon fuels accounting methodology should still keep this effect in mind. Both the 100-year GWP and failure to account for hydrogen leakage will underestimate the true climate impact of the fossil-based hydrogen value chain.

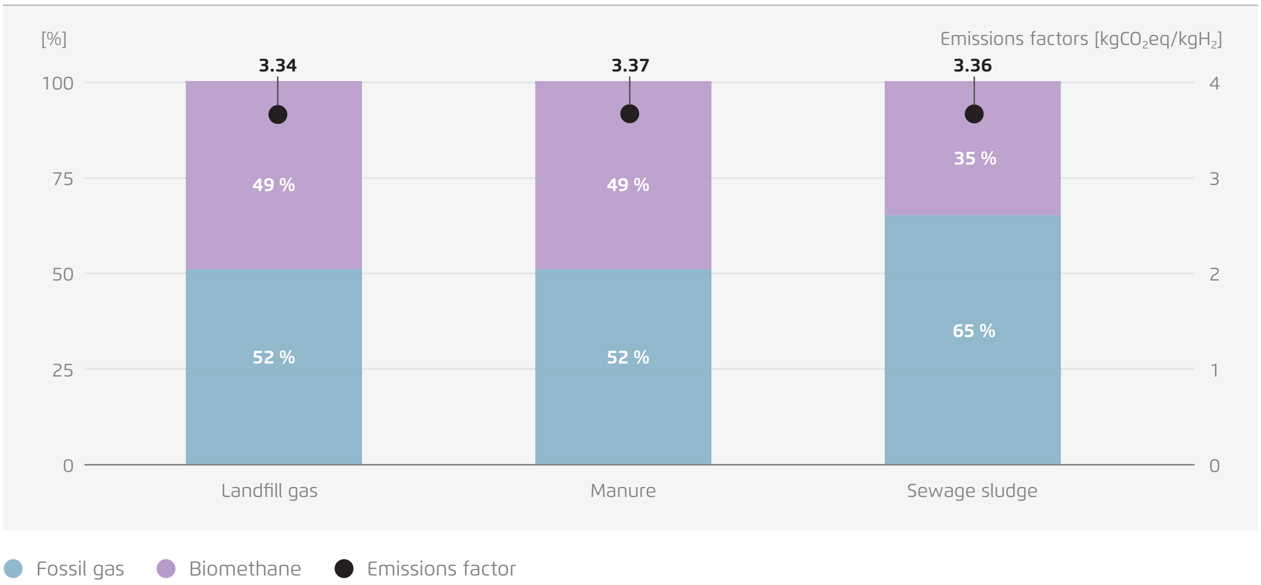
4 GHG accounting in blending or offsetting

A future emission-intensity accounting methodology will need to ensure that carbon intensities are calculated separately per feedstock input. This is necessary to avoid "carbon cross-subsidization", which would put more emitting technologies at an advantage over correctly accounted fully renewable production. Such cross-subsidization could occur in reformers using both biomethane and fossil gases or in electrolysers using both renewables and non-renewable electricity as input. It could also occur virtually via offsetting through certificates.

In fact, potential negative emissions from certain biogas feedstocks (e.g., sewage sludge, manure and landfill gas) could create large offsetting possibilities depending on the carbon intensity of the feedstock, allowing the production of hydrogen below the 3.38 $kgCO_2eq/kgH_2$ threshold while relying 52–65 percent on unabated fossil gas (see figure 18).

It seems important that the fossil part of low-carbon fuels does not benefit from a negative accounting of another input. It would thus be preferable to calculate the carbon content of low-carbon fuels separately for fuels derived from fossil gas, fuels derived from biogases and fuels derived from grid-based electricity. Allowing large-scale mixing and offsetting not only would complicate monitoring and verification of the actual carbon content of low-carbon fuels but also create several perverse incentives from an energy-transition perspective: public subsidies for the use of low-carbon fuels would provide less incentive to invest in carbon-capture technologies and in BAT along the value chain. Generally, electricity-based low-carbon fuels would be unable to compete, let alone RFNBO-compliant fuels. Furthermore, the system would pull increasingly scarce bioenergy resources away from being used as feedstock in industrial value chains to being burned as low-carbon fuel. More broadly, the effect would be an incentive to keep unabated fossil fuels in the system for longer and steer scarce bioenergy into non-priority applications.

Blending of unabated fossil fuel with negative emission biogases – meeting the threshold on paper, but not reducing process emissions or fossil gas use → Fig. 18



Deloitte for Agora Energiewende and Agora Industry (2024) with input from ICCT.

5 The role of infrastructure for fossil-based hydrogen and hydrogen (derivatives) imports

An important pre-condition for upscaling of fossil low-carbon fuels as well as imports thereof is the availability of infrastructure to transport/store the fuel as well as the CO_2.

At this point, the EU still lacks commercially proven geological CO_2 storage as well as hydrogen-storage capacity. Storing carbon under the sea is more advanced, but also more costly, than carbon storage on land. All indications are that the absence of CO_2 infrastructure will become a bottleneck during the next decade, not least due to long permitting procedures and the early-stage status of most projects.[47] This suggests that **fossil-based hydrogen production pathways will be unable to fill the immediate gap of the slower-than-expected upscaling of renewable hydrogen**. Without available geological storage for captured CO_2 and related CO_2 transport infrastructure, it is not possible to produce fossil gas-based low-carbon hydrogen. Just the opposite is the case as such grey hydrogen comes with high greenhouse gas emissions (see above). This fundamental fact should be taken into account in any potential phase-in periods of a 'low-carbon' standard. **Fossil gas-based hydrogen should only be considered for a low-carbon label once permanent geological CO_2 storage infrastructure and related CO_2 transport infrastructure are available.**

Current EU infrastructure planning does integrate hydrogen, gas and electricity to some extent but not CO_2 infrastructure. CCS infrastructure planning might in general need a boost given the slow progress that was recently noted in a special report of the European Court of Auditors[48]. More attention to ammonia transport options might also be warranted given that importing green ammonia from the US and reconverting it back into hydrogen in the EU might, even if not efficient, be below the 3.38 $kgCO_2eq/kgH_2$ threshold[49]. In contrast to this, LNG imports per ship from the US for fossil-based low-carbon fuels (with SMR) are currently above the threshold at around 4.5 $kgCO_2eq/kgH_2$[50].

The pipeline-transport route demonstrates all the way through to 2050 slightly lower GHG intensity than ship-based transport, although the choice of transport has a much smaller effect on overall emissions than controlling upstream methane and CO_2 emissions and CCS performance.[51]

Hydrogen trade flows towards and within the EU will to a large extent be shaped by infrastructure development. A network of pipelines connecting EU countries and the EU with low-cost exporters has been planned as part of the "Hydrogen Backbone" project. However, many projects are only at the planning stage and it is unlikely that all of them will be built (on time). In EU transmission infrastructure planning, connections between Germany and its close neighbors – notably Norway – are scheduled to be in place by 2030. Southern corridors should emerge sometime thereafter. Italy would be connected to Tunisia and Algeria by 2035, whilst the connection between Spain and Morocco would be ready by 2040. The repurposing of existing gas pipelines is the most cost-effective option. However, repurposed gas pipelines can no longer be used for transporting gas, meaning careful transition planning is required as only some existing gas pipelines are needed for future EU green hydrogen trade.

47 JRC (2024). Shaping the future CO2 transport network for Europe.
48 Special report 09/2024: Security of the supply of gas in the EU – EU's framework helped member states respond to the crisis but impact of some crisis-response measures cannot be demonstrated

49 Carbon Limits for Agora Energiewende and Agora Industry 2024
50 Carbon Limits for Agora Energiewende and Agora Industry 2024
51 For detailed information on methane and CO_2 emissions along various fossil and biogas value chains both with and without imports, see the slide deck done for Agora Energiewende and Agora Industry by Carbon Limits.

6 Making sure biobased hydrogen contributes to reducing GHG emissions

Biogases and biohydrogen are a category apart in the EU regulatory framework, as they are classified as renewable fuels rather than as low-carbon fuels. To be renewable, biogas and biohydrogen must meet the requirements in the EU Renewable Energy Directive but not those for RFNBOs as these are explicitly of non-biological origin. Annex VI of the Renewable Energy Directive establishes emission factors for bio feedstocks (biomass fuels). However, beyond the transport sector, the Directive does not contain limitations on food and feed-based feedstocks or provisions on minimum waste and residues shares or biomethane leakage[52]. **Before allowing for any role of biogases in low-carbon fuels production, it seems imperative to establish clear obligations on monitoring, reporting and verification of biomethane leakage at site level**. Such rules currently exist only in Denmark. That said, from a system perspective the use of biogases for burning as low-carbon fuel is only a low value and hence a low priority application.

Whilst the cost of 100 percent biohydrogen will probably not be competitive, the blending of bio and fossil feedstocks (co-processing) could occur either physically or virtually by use of certificates. Since there is no cap on food and feed-based bioenergy beyond the transport sector in EU law, allowing for the blending of (subsidized) biogases in the low-carbon fuels methodology would result in a diversion of biogases from other higher value uses (particularly in industry) and a further, indirect increase of food-production-related greenhouse gas emissions. In 2030, hydrogen production costs from blended gas could range from EUR 3.4/kgH_2 (for biomethane from landfill gas) to EUR 10.5/kgH_2 (for biomethane from manure)[53]. As shown above, the lower end of this range would be cost competitive with the other hydrogen-production routes.

We therefore recommend that renewable and low-carbon feedstocks are accounted for separately in the life-cycle GHG methodology and that they are certified separately. Furthermore, biofuels monitoring should cover detailed feedstock and related carbon-intensity reporting. Only waste and residue-based biogases should be eligible for biological hydrogen and fuel production.

52 To note that biogas/methane production is also not within the scope of the EU Methane Regulation.

53 Deloitte for Agora Energiewende 2024

7 Towards a credible monitoring and verification scheme – managing different risk profiles and value chains of fossil based low-carbon hydrogen

The quantification of greenhouse gas emissions intensity of low-carbon hydrogen requires clear measurement and accounting. In a second step, certification is required to ensure that input data can be trusted. The current absence of clear definitions/responsibilities and authorities-backed certification schemes constitute major barriers for the emerging low-carbon hydrogen economy. It also means downstream users of low-carbon hydrogen have no guarantee that the fuels they purchase are indeed low carbon.

In the EU legislative system, the duty to inform on the GHG emissions typically falls on the low-carbon fuel producer or the EU-based importer. This means gathering certification from upstream production all the way through to CO_2 storage. As can be seen in figure 19, the chain of custody – even if only considering direct emitters – is complex and would become even more so if more conversion steps are involved (e.g., LNG regasification or CCU where the use of products and their lifetime needs to be verified).

Various voluntary and mandatory monitoring, reporting and verification (MRV) standards exist covering parts of the low-carbon, fossil-hydrogen fuels value chain. Still, there is currently no recognised or integrated way for EU-based producers or importers of low-carbon fuels to prove the credentials of their product. Most importantly, MRV occurs in separate schemes for methane and for CO_2. There is no framework yet for joint monitoring. And the currently developed ISO TSO 19870 technical specification methodology for determining emissions for hydrogen standard so far does not integrate existing methane MRV practices, for example by OGMP. The future ISO standard would probably also not be aligned with EU rules since the EU Methane Regulation explicitly refers to OGMP level 4 and 5 equivalent reporting, implying for example the obligation to monitor precisely rather than use default values that would be allowed under the draft ISO rules.

The only available accounting framework that covers all parts of the fossil-hydrogen value chain and all gases is the Greenhouse Gas Protocol developed by the World Resources Institute and the World Business Council for Sustainable Development. However, because its purpose is to underpin corporate sustainability reporting, the Greenhouse Gas Protocol is relatively generic and lacks the necessary specifications and granularity of a low-carbon fuel standard.

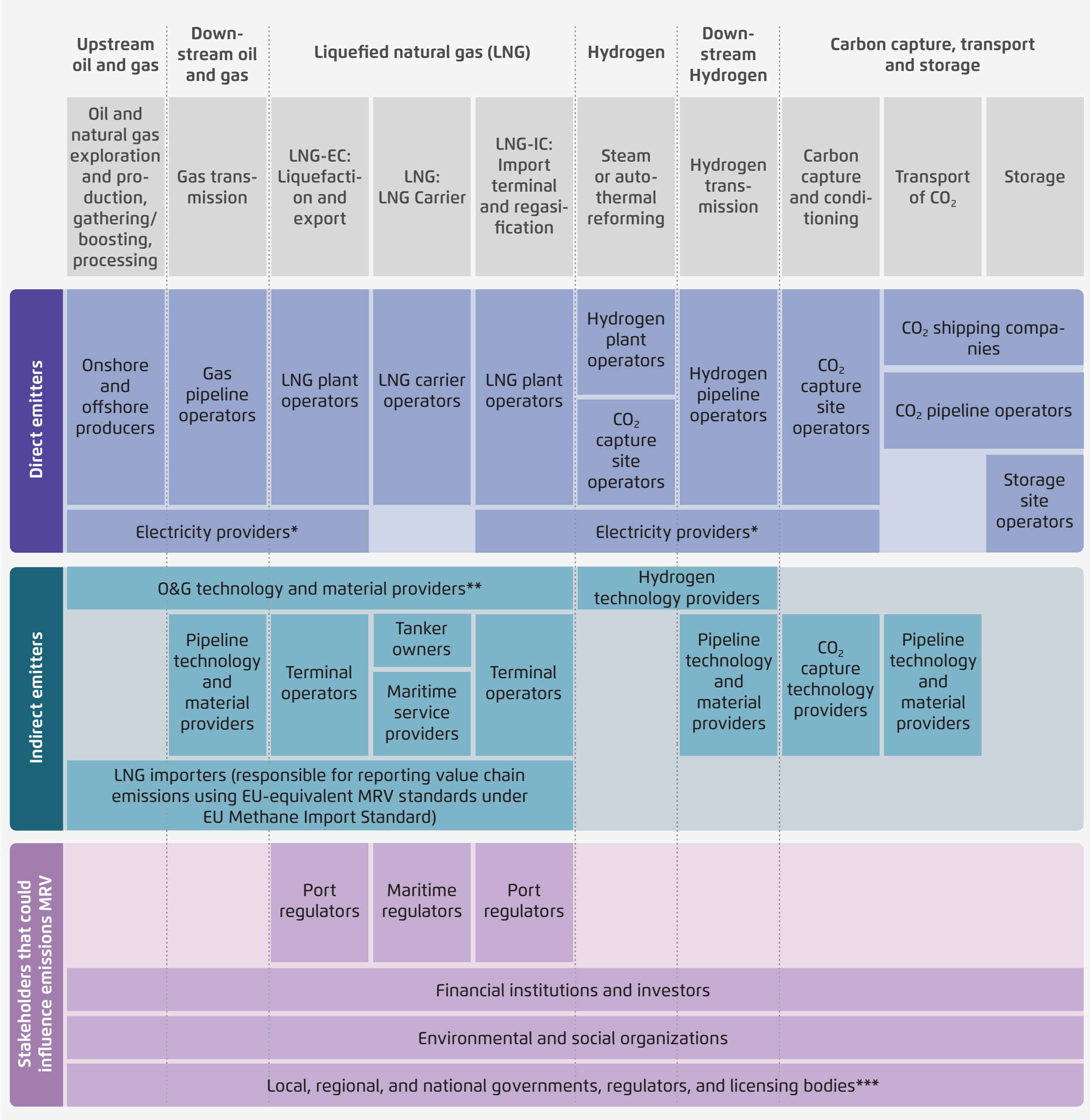
In addition to these MRV standards, a number of certification mechanisms exist for different parts of the different value chains. Again, there is no scheme in place that would cover the entire fossil-gas plus hydrogen value chain. Also the UK, which has already adopted a low-carbon standard, is still in the process of developing the certification scheme to go with its standard.

When it comes to the certification of CCS, there is certification tied to the 2009 EU CCS Directive for storage permits but no certification of emission performance or independent verification thereof. The recently adopted EU voluntary carbon-removal framework is not applicable to fossil-carbon storage, only to biogenic CO_2, so could cover only that aspect of a future EU certification system.

In a co-processing scenario of renewable biogas and fossil gas/ hydrogen, it will have to be ensured that certification occurs fully separately in order to respect the setup in EU provisions and to prevent biomaterials from being diverted away from higher priority uses (see above). Similarly, the use of low-carbon fuel certificates to offset fossil-gas emissions should not be allowed as such use would likely undermine the prioritisation provisions in the EU Hydrogen and Decarbonised Gas Markets package

Chain of custody for the fossil gas hydrogen pathway

→ Fig. 19



Carbon Limits 2024. Notes: * In the respective country where the value chain segment is occurring. ** I.e. processing and liquefaction technology, storage tank and tanker providers. *** I.e. land management, environmental, and energy agencies

and incentivise the use of hydrogen for replacing gas in heating, resulting in lower than 70 percent equivalent GHG savings. **Guarantees of origin for hydrogen and gas should therefore not be interchangeable.** One way of underpinning this restriction would be to prescribe that only actors with direct access to hydrogen infrastructure are eligible for low-carbon fuel certificates.

Finally, if a dynamically decreasing low-carbon standard is used, as we strongly recommend, guidelines will be necessary on how certification for earlier, less stringent, requirements are dealt with. This is an issue that the UK authorities are currently investigating.

8 Conclusion and recommendations

All climate neutrality scenarios foresee a role for hydrogen, particularly in applications where direct use of clean electricity is currently not an option. However, hydrogen is not a clean source of energy like the sun or wind – it is an energy carrier. The way hydrogen is produced determines whether its use increases or reduces greenhouse gas emissions.

In a climate neutral world, hydrogen will most likely be renewable, based on electrolysers powered by renewable electricity. However, for a transitional phase, some of the hydrogen used will be based on electricity taken from the grid that is not renewable, but that should come with a low-carbon intensity. And it will be derived from fossil gas, with BAT employed to abate methane and CO_2 emissions throughout the fossil-gas value chain and high efficiency carbon-capture technologies deployed at the point of hydrogen production.

The detailed analysis done by consultancies Deloitte and Carbon Limits in support of this study sends the strong message that there is no low-carbon hydrogen shortcut into Europe's future climate-neutral economy. On the contrary: while theoretically low-carbon hydrogen could outcompete renewable hydrogen on costs in the short- to medium-term, it will require real political commitment to ensure that low-carbon hydrogen actually comes with low greenhouse gas emissions throughout the entire value chain.

Particularly the fossil-gas based route of producing low-carbon hydrogen builds on several preconditions that are currently not met and that are concerning both from a climate-integrity and a security-of-supply perspective. First, it presupposes that countries supplying fossil gas will put in place effective measures to control upstream emissions (mainly methane, but also CO_2). Second, it presupposes sufficient capacity of carbon-capture technologies at the sites producing low-carbon hydrogen with efficiency levels of capturing carbon that are currently not available in the market. Third, it presupposes the availability of infrastructure for transporting the captured carbon from the point of capture to where it can be stored. Lastly, it presupposes sufficient geological storage capacity to inject and permanently store the captured carbon.

Based on the detailed analysis done by Deloitte and Carbon Limits, we make the following recommendations for the future low-carbon fuels delegated act:

1. The EU should set a dynamically decreasing maximum greenhouse gas threshold for low-carbon fuels, starting with 3.38 $kgCO_2eq/kgH_2$ (the current threshold) to reach 3 kg (referred to in the EU taxonomy) by 2030, 2 kg by 2040 and 1 kg by 2050.
2. The future low-carbon fuels delegated act should establish the greenhouse gas emissions of the marginal power-producing unit as the only way to determine the carbon content of low-carbon electrolytic production, to ensure that grid-based hydrogen is truly low carbon and to allow for renewable hydrogen to compete on fair terms.
3. The capacity under renewable electricity PPAs should be subtracted before calculating the carbon intensity of the power mix used for producing grid-based low-carbon fuels, to avoid double counting of renewables in the reference power mix.
4. The default upstream emission factor of 9.7 gCO_2eq/MJ should be complemented by country-specific, preferably by basin-specific, emissions factors until site-specific rules under the EU Methane Regulation come into effect. Not doing so would underestimate real-world emissions from fossil-based hydrogen by a factor of 2.5 for Europe by 2040.
5. The EU should acknowledge that Europe could become heavily reliant on a very limited number of suppliers of fossil gas for hydrogen production if currently lacking efforts to implement BAT along the value chains were to reflect a broader trend; thus adding a significant risk to Europe's future energy security.

6. The EU should also acknowledge that at this point, the availability of highly efficient carbon capture technologies at scale and reasonable cost is a bottleneck in the fossil-gas based 'low-carbon' hydrogen route.
7. The low-carbon fuels methodology should prioritise the permanent geological storage of the captured CO_2 and not allow other methods such as carbon capture and use applications or "Enhanced Oil Recovery" that either are not permanent or not sufficiently low carbon.
8. The carbon content of low-carbon fuels should be calculated separately for fuels derived from fossil gas, fuels derived from biogases and fuels derived from grid-based electricity. Allowing mixing and offsetting not only would complicate monitoring and verification of actual carbon content of low-carbon fuels, but also would create perverse incentives from an energy transition perspective.
9. Before allowing for any role of biogases in low-carbon fuels production, the EU should establish clear obligations on monitoring, reporting and verification of biomethane leakage at site level. Currently EU rules do not address biomethane leakage at the point of production/storage.
10. Renewable and low-carbon feedstocks should be separately accounted for in the low-carbon fuels methodology and also separately certified. Furthermore, only waste and residue-based biogases should be eligible for low-carbon fuels production. This would avoid perverse incentives for biomethane blending.
11. The EU should establish from the start an obligation to deploy BAT for hydrogen leakage control as part of the low-carbon fuels accounting methodology, given the significant but indirect role of hydrogen in contributing to a warming climate.
12. The EU should engage in international partnerships, for example with the UK and the US, to establish scientifically sound methodologies and standards for low-carbon hydrogen based on independently verified reporting of emissions, as well as regulatory dialogues to manage the emerging restructuring of value chains and new trade maps. Life-cycle accounting for both renewable and non-renewable fuels should be continuously developed in the future, for example to cover embodied emissions and include hydrogen leakage.
13. Overall, the EU's low-carbon fuels methodology and policy framework should steer investments into grid-based production pathways, as by the mid 2030s electrolysers operating continuously should produce either renewable or low-carbon hydrogen almost everywhere in Europe.

References

Agora Energiewende, Agora Industry (2021). *12 insights on hydrogen*. https://www.agora-industry.org/publications/12-insights-on-hydrogen

Agora Energiewende (2023). *Breaking Free from Fossil Gas*. A new pathway to a climate neutral Europe. https://www.agora-energiewende.org/publications/breaking-free-from-fossil-gas

Agora Industry and TU Hamburg (2023): Hydrogen import options for Germany. *Analysis with an in-depth look at synthetic natural gas (SNG) with a nearly closed carbon cycle*, https://www.agora-industry.org/publications/hydrogen-import-options-for-germany-summary

Balcombe, P.; Heggo, D.A.; Harrison, M. (2022). *Total Methane and CO_2 emissions from Liquefied Natural Gas Carrier Ships: the first primary measurements.* Environ Sci Technol. 2022 Jul 5; 56(13): 9632–9640.

California Air Resources Board (2018). *Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard*

Carbon Limits (2024). *Support on regulatory approach for LCH in the EU (Carbon Limits for Agora Energiewende and Agora Industry 2024)*. URL: https://www.agora-energiewende.org/publications/support-on-regulatory-approach-for-lch-in-the-eu

Climate Bonds Initiative (2023). *Hydrogen criteria background paper*

Commission Delegated Regulation (EU) 2023/1184 establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin

Commission Delegated Regulation (EU) 2023/1185 establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and by specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin and from recycled carbon fuels

Deloitte Finance (2024). *Assessing the impact of the low carbon hydrogen regulation in the EU (Deloitte for Agora Energiewende and Agora Industry 2024)*. URL: https://www.agora-energiewende.org/publications/assessing-the-impact-of-low-carbon-hydrogen-regulation-in-the-eu

Directive 2009/31/EC on the geological storage of carbon dioxide

Directive (EU) 2023/2413 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources.

Directive (EU) 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive 2023/1791 and repealing Directive 2009/73/EC

Esquivel-Elizondo, S.; Hormaza Mejia, A.; Sun, T.; Shrestha, E.; Harmburg, S.p.; Ocko, I.B. (2023). *Wide range in estimates of hydrogen emissions from infrastructure*. Front. Energy. Res, 04/08/2023. Volume 11 – 2023.

European Commission (2020): A hydrogen strategy for a climate-neutral Europe. *COM(2020) 301 final*.

European Commission, Joint Research Center, Tumara, D., Uihlein, A. and Hidalgo Gonzalez, I., *Shaping the future CO_2 transport network for Europe*, Publications Office of the European Union, Luxembourg, 2024, https://data.europa.eu/doi/10.2760/582433, JRC136709.

European Court of Auditors (2024). *Security of the supply of gas in the EU – EU's framework helped member states respond to the crisis but impact of some crisis-responded measures cannot be demonstrated*. Special report 09/2024.

European Hydrogen Observatory (2024). *The European hydrogen market landscape*. Updated February 2024

FCHEA (2022). *How the Inflation Reduction Act of 2022 will advance a US Hydrogen Economy*.

Hydrogen4EU (2022). *Charting pathways to enable net zero*. https://www2.deloitte.com/fr/fr/pages/fusions-acquisitions/articles/economic-advisory/role-of-hydrogen-in-european-energy-transition.html

ICCT (2021). *Life-cycle greenhouse gas emissions of biomethane and hydrogen pathways in the European Union*. Updated version June 14, 2022. https://theicct.org/publication/life-cycle-greenhouse-gas-emissions-of-biomethane-and-hydrogen-pathways-in-the-european-union/

IEA (2021). *Comparison of the emissions intensity of different hydrogen production routes, 2021*. (Last updated 29 Jun 2023)

IEA (2023). *Global Hydrogen Review 2023*. https://www.iea.org/reports/global-hydrogen-review-2023

Jacobs, N (2023). *EPA data show across the board drops in total methane emissions in top oil, nature gas producing basins*. EID Climate

Oil Change International (2024). *On thin ice: Norway's fossil ambitions and the EU's green energy future*, https://zerocarbon-analytics.org/wp-content/uploads/2024/02/On-Thin-Ice.pdf

Regulation (EU) 2024/1787 on the reduction of methane emissions in the energy sector and amending Regulation 2019/942

Regulation (EU) 2024/1735 on establishing a framework of measures for strengthening Europe's net-zero technology manufacturing ecosystem

Shirizadeh, B., Villavicencio, M., Douguet, S. et al (2023). *The impact of methane leakage on the role of natural gas in the European energy transition.* Nat Commun 14, 5756 (2023).

Tianyi Sun, Eriko Shrestha, Steven P. Hamburg, Roland Kupers, and Ilissa B. Ocko (2024). *Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales Environmental* Science & Technology 2024 58 (12), 5299-5309

Warwick, N.J.; Archibald, A.T.; Griffiths, P.T.; Keeble, J.; O'Connor, F.M.; Pyle, J.A.; Shine, K.P. (2023). *Atmospheric composition and climate impacts of a future hydrogen economy.* Atmospheric Chemistry and Physics. Volume 23, issue 20.

Publications by Agora Energiewende

In English

The benefits of energy flexibility at home
Leveraging the use of electric vehicles, heat pumps and other forms of demand-side response at the household level

EU policies for climate neutrality in the decisive decade
20 Initiatives to advance solidarity, competitiveness and sovereignty

The roll-out of large-scale heat pumps in Germany
Strategies for the market ramp-up in district heating and industry

Transitioning away from coal in Indonesia, Vietnam and the Philippines
Overview of the coal sector with a focus on its economic relevance and policy framework

Hydrogen import options for Germany (Summary)
Analysis with an in-depth look at synthetic natural gas (SNG) with a nearly closed carbon cycle

Ensuring resilience in Europe's energy transition
The role of EU clean-tech manufacturing

Levelised cost of hydrogen
Making the application of the LCOH concept more consistent and more useful

Breaking free from fossil gas
A new path to a climate-neutral Europe

How Europe can make its power market more resilient
Recommendations for a short-term reform

Coal phase-out in Germany
The multi-stakeholder commission as a policy tool

Climate-neutral power system 2035 (Summary)
How the German power sector can become climate-neutral by 2035

Delivering RePowerEU
A solidarity-based proposal for financing additional green investment needs

Regaining Europe's energy sovereignty
15 priority actions for RePowerEU

All publications in English are available on our website: www.agora-energiewende.org

Publications by Agora Energiewende

In German

Serielle Sanierung
Effektiver Klimaschutz in Gebäuden und neue Potenziale für die Bauwirtschaft

Wasserstoffimporte Deutschlands
Welchen Beitrag können Pipelineimporte in den 2030er Jahren leisten?

Der Sanierungssprint
Potenzial und Politikinstrumente für einen innovativen Ansatz zur Gebäudesanierung

Die Energiewende in Deutschland: Stand der Dinge 2023
Rückblick auf die wesentlichen Entwicklungen sowie Ausblick auf 2024

Haushaltsnahe Flexibilitäten nutzen
Wie Elektrofahrzeuge, Wärmepumpen und Co. die Stromkosten für alle senken können

Der CO_2-Preis für Gebäude und Verkehr
Ein Konzept für den Übergang vom nationalen zum EU-Emissionshandel

Wasserstoff-Importoptionen für Deutschland
Analyse mit einer Vertiefung zu Synthetischem Erdgas (SNG) bei nahezu geschlossenem Kohlenstoffkreislauf

Windstrom nutzen statt abregeln
Ein Vorschlag zur zeitlichen und regionalen Differenzierung der Netzentgelte

Roll-out von Großwärmepumpen in Deutschland
Strategien für den Markthochlauf in Wärmenetzen und Industrie

Ein neuer Ordnungsrahmen für Erdgasverteilnetze
Analysen und Handlungsoptionen für eine bezahlbare und klimazielkompatible Transformation

Rückenwind für Klimaneutralität
15 Maßnahmen für den beschleunigten Ausbau der Windenergie

Klimaneutrales Stromsystem 2035 (Zusammenfassung)
Wie der deutsche Stromsektor bis zum Jahr 2035 klimaneutral werden kann

Die Energiewende in Deutschland: Stand der Dinge 2022
Rückblick auf die wesentlichen Entwicklungen sowie Ausblick auf 2023

All publications are available on our website: www.agora-energiewende.de

Publication details

About Agora Energiewende
Agora Energiewende develops scientifically sound, politically feasible ways to ensure the success of the energy transition – in Germany, Europe and the rest of the world. The organisation works independently of economic and partisan interests. Its only commitment is to climate action.

Agora Energiewende
Agora Think Tanks gGmbH
Anna-Louisa-Karsch-Straße 2
10178 Berlin | Germany
P +49 (0) 30 7001435-000

www.agora-energiewende.org
info@agora-energiewende.de

Agora Industry
Agora Think Tanks gGmbH
Anna-Louisa-Karsch-Straße 2
10178 Berlin | Germany
P +49 (0) 30 7001435-000

www.agora-industry.org
info@agora-industrie.de

Proofreading: Jonathan Stearns
Typesetting: Urs Karcher
Title picture: boedefeld1969 | Adobe Stock

334/04-I-2024/EN
Version 1.3, September 2024

This publication is available for download under this scan code.