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Assessing the impact of low-carbon hydrogen regulation in the EU

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Executive summary

The European Climate Law was adopted in 2021[1]. This law stipulates a reduction of greenhouse gas emissions (GHG) of 55% by 2030 and climate neutrality of the European economy by 2050. Versatile, indispensable in some sectors, and complementary to electrification, clean hydrogen is a key element in achieving these climate objectives. However, the hydrogen economy is still in its infancy. **Establishing clear and effective regulation, definitions, and certification schemes is a prerequisite for market creation and investments.**

Following the official adoption of the Hydrogen and Decarbonised Gas package in May 2024, the European Commission must, within a year, prepare a Delegated Act on Low-Carbon Fuels for which low-carbon hydrogen is the key component. This Delegated Act will establish the accounting rules and thresholds required to define hydrogen production methods as low-carbon (and, as such, form the basis of a certification scheme). It should encompass different production routes, including power grid-based electrolysis, fossil gas-based production (with CCUS), and imports (from outside the EU), all of which have the potential to contribute to reducing greenhouse gas emissions. **The upcoming Delegated Act will complement the existing regulation on renewable hydrogen[2],** which notably introduced an emission threshold and a lifecycle GHG accounting framework, to account for renewable fuels of non-biological origin (RFNBO).

This study provides scientific and quantitative evidence on the potential implications of key regulatory design aspects of the forthcoming Delegated Act on Low-Carbon Fuels. Policy decisions will inevitably shape the competition between technologies, with short- and long-term implications on the nascent hydrogen industry's environmental integrity, economic competitiveness, and resiliency. Using a detailed modelling approach, we quantify the effects of key regulatory parameters currently under debate and that policymakers should fix in the forthcoming Delegated Act. The modelling framework deploys Deloitte's European Electricity Model (DEEM), i.e., the power system module of Deloitte's energy system model (DARE), and the Hydrogen Pathway Explorer (HyPE), an international hydrogen trade model. It comprehensively represents the future of the European electricity system, the potential for hydrogen production, pipeline trade and seaborne imports.

The Renewable Energy Directive (RED III)[3] sets a 94 gCO_2eq/MJ fossil fuel comparator and requires at least a 70% GHG emission reduction, translating to a carbon intensity threshold for hydrogen of 3.38 $kgCO_2eq/kgH_2$. The Delegated Act on greenhouse gas emissions accounting methodology[4], from February 2023, proposes three different accounting methods to calculate the carbon intensity of fuels of non-biological origin produced from grid electricity but leaves open which one to use in practice. These methods vary in simplicity, temporal granularity, and accuracy of information. At the two extremes, one method uses country-specific average annual grid-intensity factors while another method involves real-time monitoring of hourly power plant dispatching, where the carbon intensity is determined by the marginal unit. Based on existing power mixes, only Sweden, Norway, France, and Switzerland can today produce grid-based low-carbon hydrogen (LCH) below the current threshold, if the annual average carbon-intensity method is applied.

1 Regulation (EU) 2021/1119 of 30 June 2021 establishing the framework for achieving climate neutrality

2 The Renewable Energy Directive RED II (Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable energy sources) and the subsequent RFNBO Delegated Acts of February 2023 on minimum GHG threshold and GHG accounting methodology

3 Directive (EU) 2023/2413 of 18 October 2023 on the promotion of the use of energy from renewable energy sources

4 Delegated Regulation (EU) 2023/1185 of 10 February 2023 establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and 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

Compared to the rigid yearly average method, the hourly marginal one encourages electrolyser operations at times when renewables or nuclear power generation dominate the electricity mix, boosting electrolytic low-carbon hydrogen and RFNBO production (even if the yearly average value is above the threshold). By failing to incentivise the use of electricity from the grid during hours when carbon emissions are low, we find that the yearly average method results in emissions that are 30 $MtCO_2eq$ higher (over the period to 2050) than the hourly marginal method.

Fossil gas-based production could comply with the threshold if steam methane reformers are equipped with advanced CCS technologies (capture rate of 90% or more) and upstream fossil gas production has a minimal environmental footprint. The environmental footprint of upstream natural gas production varies widely between countries. For instance, today, fossil gas-based hydrogen production in the EU, sourcing natural gas from the US or Algeria, would not be compliant with the current carbon intensity threshold even if the most advanced capture technologies were used. However, by adopting best available technologies (BAT) to reduce emissions in the natural gas value chain, it would be possible to produce fossil gas-based hydrogen with a carbon intensity close to 1 $kgCO_2eq/kgH_2$. Doing so requires a strong commitment and significant efforts of natural gas producers to abate their upstream emissions. In addition, fossil gas-based hydrogen production is subject to uncertainties regarding the timeline and cost of CO_2 transport and storage infrastructure and the price of natural gas.

Hydrogen production costs vary significantly by technology and country, influenced by natural gas and electricity price fluctuations, weather conditions, and infrastructure availability. National disparities in terms of renewable endowments, legacy power mixes, and access to CO_2 storage sites or hydrogen import infrastructure translate into a diversity of supply trajectories across the EU countries. For the least ambitious interpretation of key regulatory design parameters of the upcoming Delegated Act on Low-Carbon Fuels, i.e., a static carbon-intensity threshold and annual average grid intensity, as the basis for carbon accounting, our model-based analysis finds:

- **RFNBO takes half of the market from 2030 onwards.** The other half is shared between fossil-based and grid-based LCH, and LCH imports. The split of this second half depends on many uncertain factors determining technology feasibility and competitiveness (i.e. CO_2 transport and storage infrastructure availability, natural gas prices and associated upstream emissions, development of import infrastructure, and nuclear energy policies, among others).
- Throughout the transition, the decreasing carbon intensity of the grid, in combination with falling electricity prices, significantly strengthen the business case for grid-connected electrolysers. **Grid-based hydrogen production emerges as the largest supply route** and grows from around 15% of total EU demand in 2030 to 35% in 2050. This translates to around 30 GW of grid-connected electrolysers in 2030 and nearly 210 GW in 2050.
- **RFNBO production from captive renewables, either off-grid or via a power purchase agreement (PPA), meets around 32% of the EU's hydrogen demand in 2030 and 12% in 2050.** It has a crucial role in building the renewable hydrogen market but experiences moderate growth afterwards – superseded by grid-based production, which, however, becomes increasingly RFNBO-compliant, i.e., qualifies as renewable hydrogen.
- **Fossil gas-based technologies, which are cost-competitive in some member states, could supply almost one-third of EU hydrogen demand by 2050.**

However, this varies significantly by country depending on renewable energy endowments and proximity to CO_2 storage sites. However, including methane leaks and associated CO_2 emissions within the lifecycle GHG emission accounting is paramount and should be as granular as possible[5]. This would limit the number of eligible suppliers in the short-term and provide incentives to adopt BAT in the long term.

- **The EU could source up to 35% of its hydrogen needs from imports by 2030,** with about half of these imports coming from Norway, where fossil gas-based and electrolytic hydrogen production costs are low. Increasingly cost-competitive domestic production reduces import shares in the long term, dropping to some 15% of total demand by 2050.
- **Hydrogen supply within the EU is supplemented by pipeline trade among member states.** Hydrogen flows from low-cost producers like Spain and Portugal to higher-cost countries such as Belgium, the Netherlands, and Germany.

However, compatibility with the EU's net-zero target would require the carbon intensity threshold to decrease from 3.38 to 1 $kgCO_2eq/kgH_2$ in 2050. Adopting a decreasing threshold would yield cumulative GHG emission savings of up to 230 $MtCO_2eq$ over the period to 2050, as compared to a static threshold. The production and market shares of fossil gas-based low-carbon hydrogen are then driven by the extent to which gas suppliers can adopt the most performing technologies to cut upstream emissions. Without widespread adoption of BAT, only natural gas from Norway would be compliant with such a decreasing threshold for low-carbon hydrogen production. This would cloud the outlook for fossil gas-based low-carbon hydrogen in the EU: in a scenario with decreasing thresholds and failure to implement BAT, fossil gas-based low-carbon hydrogen peaks by the mid-2040s and accounts for only around 10% of EU hydrogen supply by 2050. In this case, domestic RFNBO production covers about 60% of the supply, while imports of essentially RFNBO add up 20% in 2050.

Variable renewables, like solar PV and wind power, will become the backbone of the European power system and a cornerstone of decarbonisation through the direct and indirect electrification of end-uses. It is, therefore, essential that today's regulatory frameworks safeguard the achievement of long-term objectives. We find that ambitious regulatory designs, i.e., a granular carbon accounting method for grid-based hydrogen in combination with a carbon-intensity threshold that gradually falls over time, offer numerous advantages:

- **Carbon accounting based on power plant dispatch allows electrolysers to respond to real-time conditions** of the power system and thus provide much needed flexibility for the integration of growing shares of renewables. This accounting rule also allows grid-based electrolysis to flourish in a greater number of countries and thus prepare a wide-spread switch to renewable hydrogen in the long term.
- **The carbon intensity-threshold of 3.38 $kgCO_2eq/kgH_2$ is a reasonable compromise to stimulate first investments.** However, if this intensity was to stay constant through 2050, fossil gas-based hydrogen would, in the long-term, become a major GHG emitter and other sectors would need to make substantial compensating efforts in achieving climate neutrality for the European economy[6].
- **It is therefore crucial to be clear from the beginning, that carbon intensity-thresholds will need to fall over time.** As such, natural gas producers are continuously incentivised to make their best efforts in reducing upstream emissions. Moreover, clarity that fossil gas-based hydrogen will be subject to increasingly ambitious environmental standards avoids harmful technology lock-in effects or stranded assets along the gas value chain.

5 Ideally by natural was basin, or at least using country-specific upstream emissions. Using an average value would only introduce biases and would lead to underperformance

6 With a static threshold, the emissions associated with electricity and hydrogen represent up to 60 $MtCO_2eq$ in 2050, mainly driven by non-abated emissions of fossil gas-based LCH production. This is equivalent to the total net emissions of the energy and non-energy related sectors in 2050 of the LIFE scenario of the European Commission 2040 Impact Assessment. See Table 6 of the official assessment available at: 2040 Impact Assessment

1. Setting the scene

1.1 Hydrogen policymaking in the EU

In June 2021 the Council of the EU formally adopted the European Climate Law, initiating the EU's journey to climate neutrality by 2050. This monumental undertaking will require a complete decarbonisation of the economy. Energy use – responsible for 75% of EU GHG emissions in 2022[7] – is at the heart of the process, and a rapid transformation of the energy sector is a prerequisite to achieving climate objectives. The roll-out of clean energy technologies requires unprecedented speed and scale. This needs to be accompanied by concerted efforts to develop and implement ambitious policies. Regulation is crucial for guiding investments in the desired direction. **A well-designed regulatory framework enables appropriate investments by setting clear and coherent targets and standards as well as providing the right economic incentives.**

Versatile, indispensable in some sectors and complementary to electrification, **clean hydrogen will undoubtedly have a major role in the decarbonisation story.** Clean hydrogen can effectively reduce industrial emissions as a feedstock in the sustainable production of chemicals or steel or as an energy source providing carbon-free high-temperature heat. Hydrogen could also fuel the transport segments which cannot easily be electrified either by directly feeding a fuel cell engine (especially in heavy road transport) or as a feedstock in the production of sustainable alternative fuels (ammonia or methanol for the maritime sector, e-Kerosene in aviation). In addition, it can store energy and serve as fuel for backup power production to cope with the variability of renewables in future power grids.

Over the last five years, increasing climate awareness and ambitions have created a significant momentum around clean hydrogen uptake. Hydrogen has, as such, made its way also into European energy planning. In addition to the ambitious targets set by the European Commission, eighteen member states have released national hydrogen strategies to date[8]. These ambitions are beginning to materialise concretely with the emergence of dedicated EU regulations, such as the Hydrogen and decarbonised gas market package proposed in 2021 and recently adopted, and the deployment of various support mechanisms for project developers, including the European Hydrogen Bank and the Important Projects of Common European Interest (IPCEI) on hydrogen. In 2023, member states were required to submit updated drafts of their National Energy and Climate Plans (NECPs). These drafts outlined ambitions and policies concerning hydrogen, in accordance with the 2030 climate and energy legislation. The updated NECPs had to incorporate key obligations from RED III, including targets, measures, and tools to meet RFNBO objectives. Some of the updated NECPs include national targets for electrolyser deployment and financing schemes to support the growth of the hydrogen economy[9].

Nevertheless, the hydrogen economy is struggling to take off. Whilst more than 600 projects have been announced in the EU, only 10% advanced to final investment decision stage[10]. Investors and potential off-takers seem to await the finalisation of the regulatory frameworks before committing financially. Greater clarity on the certification schemes is expected. Indeed, such certifications determine qualifications for subsidies and inclusions

7 EU energy statistical pocketbook and country datasheets, European Commission

8 National strategies, European Hydrogen Observatory

9 National energy and climate plans, European Commission

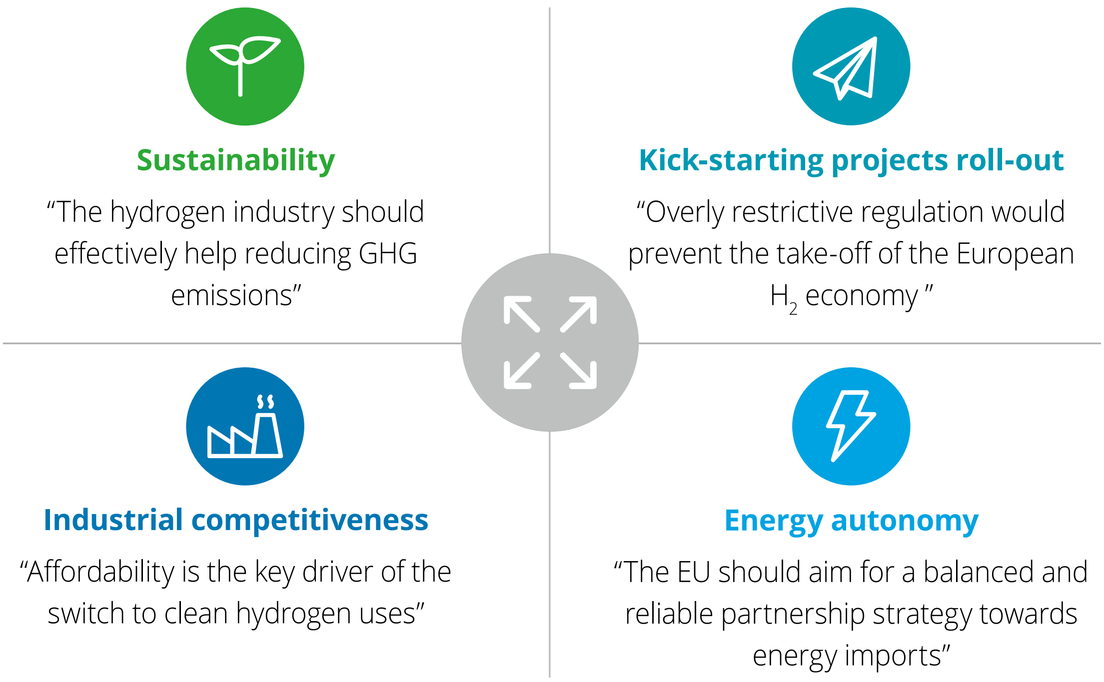
10 Hydrogen Production and Infrastructure Projects Database, International Energy Agency

in quotas, the two cornerstones of the low-emissions hydrogen business case in the short-term. **The absence of clear definitions and authorities-backed certification schemes constitute major barriers for the emerging low-carbon hydrogen economy.**

Developing comprehensive regulation for clean hydrogen supply is challenging, as it must encompass production from very different technologies and energy sources. Various hydrogen supply routes, that all have a potential to contribute to reducing greenhouse gas emissions, are available to European actors. Each presents distinct challenges and opportunities:

- **Natural gas reforming with Carbon Capture and Storage/Utilisation ('CCUS'):** Frequently claimed as the least-cost production pathway in the short-term[11], its economic viability is heavily reliant on CO_2 transport and storage infrastructure, which are not developed at scale yet. Emissions gains compared to unabated fossil-gas based hydrogen[12] will be highly dependent on upstream methane and CO_2 emissions in the natural gas value chains, achievable CO_2 capture rates, and permanence of CO_2 storage.
- **Electrolysis:** This production pathway does not generate direct CO_2 emissions but induces additional power consumption. If this electricity is drawn from an emission-intensive power grid, the produced hydrogen can have a higher emission intensity than unabated fossil gas-based hydrogen. However, sourcing electricity from new renewables or a carbon-free grid would yield a negligible carbon footprint. Electrolysers can also serve as a flexible solution in grids with a high share of renewables, enabling a better match between electricity consumption and production profiles. Expected cost decrease for both, renewables and electrolysers, suggests that electrolytic hydrogen production costs fall sharply in the coming decades.
- **Biomethane reforming:** Depending on the feedstock used for biomethane production and the availability of long-term carbon storage techniques, this production pathway can lead to negative emissions. Yet, biogas supply is likely to be scarce and costly and might be better used to reduce emissions in other sectors where fewer alternatives are available.
- **Imports:** Europe could benefit from lower energy production costs abroad (where there are better renewable energy endowments or large gas reserves) by importing hydrogen at a lower cost than local production. Yet, this has to take into account potential lack of clarity on the climate integrity of those imports, security of supply concerns and geopolitical aspects as well as a risk of slowing down local hydrogen industries.

Figure 1. Illustration of the key dimensions at play with the low-carbon regulation



11 As highlighted for instance in the following study "On the cost competitiveness of blue and green hydrogen"

12 Or also called "grey hydrogen".

Policy decisions will inevitably shape the competition between technologies, having short and long-term consequences on EU environmental record, economic activity, and energy security
Hydrogen regulation must balance the requirements for environmental integrity with economic and strategic priorities. The basic premise is that clean hydrogen production choices are aligned with climate ambitions. Stringent emissions standards should ensure that hydrogen production generates minimal direct and indirect GHG emissions. However, this must be carefully calibrated to support the hydrogen economy's take-off and foster investments in production assets. In fact, a set of environmental criteria that is too restrictive would hinder the realisation of hydrogen projects and imperil the sector. A careful eye should be kept on production costs as well. It is crucial to ensure that European industry has access to cost-competitive clean resources to preserve international competitiveness and avoid relocation and economic downgrading. Lastly, regulation should enhance energy autonomy and foster security of supply.

1.2 Overview of EU regulation concerning low-carbon hydrogen

The multiple production technologies and energy sources offer numerous combinations to produce chemically identical hydrogen molecules. The distinction between production routes is often made by associating production options with "hydrogen colours". However, the European Union adopted the use in its official documents and communications of a different hydrogen terminology, categorising supply options depending on the feedstocks used and emissions intensities. In the EU text, three concepts are put forward for their contribution to the energy transition: "renewable gas", "renewable fuel of non-biological origin (RFNBO)", and "low-carbon hydrogen (LCH)".

Common to these three categories is the requirement to meet a minimum emission reduction threshold compared to fossil fuel alternatives. However, they are differentiated by production inputs.

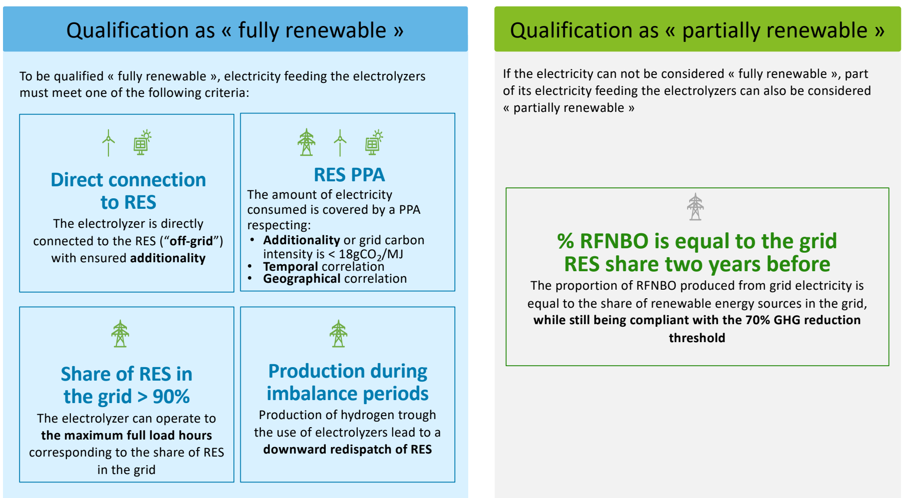
- All gases from renewable energy sources can be labelled "renewable" whilst only hydrogen and derivatives whose energy content is derived from renewable electricity can be certified RFNBO. As such, hydrogen produced from renewable biomass would be excluded from this definition and would fall under the definition of "biogas" within EU regulation.
- In contrast, "low-carbon hydrogen" is defined rather broadly as the share of "hydrogen the energy content of which is derived from non-renewable sources, which meets the greenhouse gas emission reduction threshold of 70% compared to the fossil fuel comparator"[13].

Despite the usage of the term "low-carbon hydrogen" in various discussions and documents, no clear-cut boundaries to the category have been defined yet. The disclosed definition could encompass fossil gas-based (coupled with biogas or CCUS) and electrolytic (with electricity sourced from low-carbon grids or production assets such as nuclear or CCGTs with CCS) routes. Yet, the exact requirements for those production methods are still unknown. To address this gap, the European Commission must issue a Delegated Act laying out precise criteria for low-carbon hydrogen. This act will establish the standards, accounting rules and thresholds required to categorise hydrogen production methods as low-carbon, facilitating clearer guidance for industry practices and regulatory compliance.

In contrast, clarity on the RFNBO definition was brought up in February 2023 through the release of two Delegated Acts.

- The Delegated Act on a methodology for renewable fuels of non-biological origin[14] introduces the concept of "fully renewable electricity". It lays out multiple – while being overall fairly restrictive – situations in which consumed electricity can be considered "fully renewable" (Figure 2). The overarching idea is that the consumed renewable electricity should not be diverted from another use and should be related to a particular renewable asset.

Figure 2. Overview of criteria to qualify as "renewable" electrolysers electricity consumption



13 As defined in Article 2, point (35) of RED II. This definition is also used in Article 2, point (11) of the Hydrogen and Decarbonised Gas Market Directive

14 Delegated Regulation (EU) 2023/1184 of 10 February 2023 establishing a Union methodology setting out detailed rules for the production of renewable fuels of non-biological origin

The default situation will require hydrogen producers to have a PPA with a new renewable installation ("additionality criteria") in the same bidding zone ("geographical correlation") and to adjust its consumption to the asset production ("temporal correlation"). These requirements may be relaxed if:

- The electrolyser is producing during an imbalance period (its power consumption is considered "fully renewable");
- The electrolyser is in a bidding zone with more than 90% renewables (its power consumption is then considered "fully renewable" for a limited number of hours);
- The electrolyser has no grid connection and is only linked to renewables (only the additionality criteria then apply);
- The electrolyser is located in a bidding zone with a carbon intensity lower than 18 gCO_2eq/MJ (the additionality criteria is then removed).

• The Delegated Act on greenhouse gas emissions accounting methodology[15] outlines the accounting rules to compute the greenhouse gas savings from fuels of non-biological origin (i.e., hydrogen and derivatives) and sets out the minimum emissions threshold. Emissions are assessed using a lifecycle assessment framework, and at least 70% of savings compared to a "fossil fuel comparator" are required to qualify for RFNBO. The 70% emissions savings compared to the fossil fuel comparator corresponds to a maximum hydrogen carbon footprint of 3.38 $kgCO_2eq/kgH_2$. Electricity carbon footprint is either set at zero if the electricity can be considered "fully renewable" regarding the Delegated Act on a methodology for renewable fuels of non-biological origin or should be assessed by selecting one of the three methodologies presented in the document's annex. Table 1 summarises the three different methodologies available, their conceptual differences, and their potential implications for electrolyser behaviours and system emissions.

Table 1. Presentation of the different grid emissions accounting methodologies in the DA 2023/1185

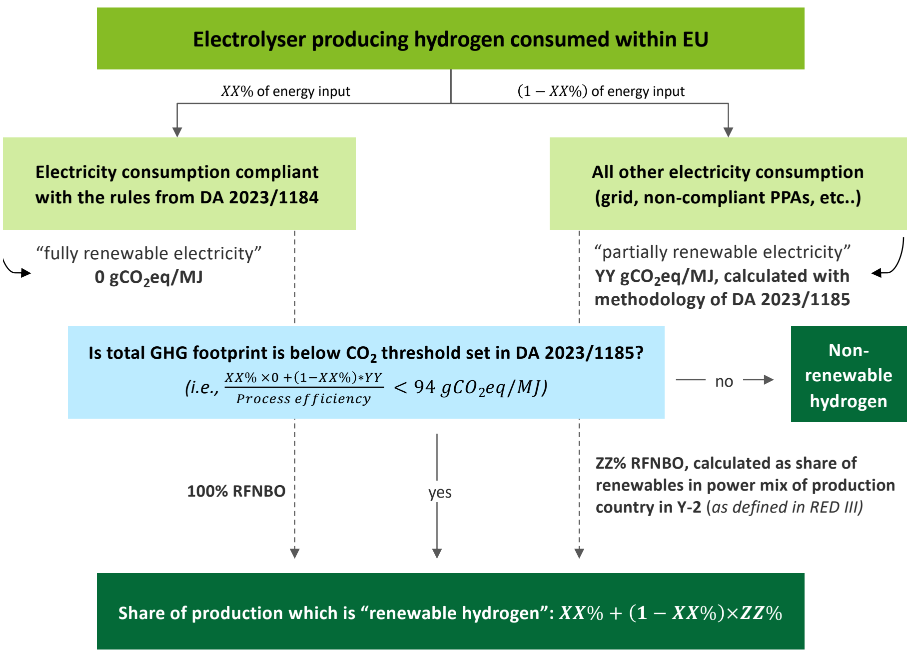
	Methodology presentation	Temporal granularity	Implications if implemented alone
a)	**Average grid-intensity factor** A yearly-average grid intensity mix is calculated using standard factors and the latest available national power production data. Emissions factors to be used in the EU are provided in appendix of the Delegated Act and based on 2020 data. This factor can then be used to calculate the GHG footprint of the electrolyser power input. **This implies that all electricity consumed by the grid is viewed in the same manner, regardless of usage or consumption time.**	Single pre-determined annual value	This rigid methodology fails to depict the hourly variations of the electricity GHG mix and, as such, **does not incentivise electrolyser flexibility.** The standard emissions factors would separate countries in two different categories: - Those whose average emission factor is low enough to produce grid-based hydrogen under the threshold would be **incentivised to maximise electrolyser load factors;** - The other countries would be completely **prevented from producing grid-based low-carbon hydrogen.**
b)	**Full load hours** Emissions are computed compared to the number of "carbon-free" power production hours in the preceding year (H). Consumed electricity is then accounted as follows: - 0 gCO_2eq/MJ for hours up to H - 183 gCO_2eq/MJ for hours above H	Pre-determined annual values	Whilst acknowledging variations of grid intensity, this methodology creates **little incentives for electrolyser flexibility.** Indeed, the different parameters are pre-determined, and the final calculated GHG footprint is independent of the grid situation during electrolyser production. Yet, it caps the maximum hours of electrolyser functioning.
c)	**Emissions of the marginal unit** This method assesses the emissions hourly based on the carbon intensity of the last unit dispatched to meet demand. This usually corresponds to the most carbon-intensive power plant in the producing mix. **Conceptually, this amounts to considering that the electrolyser is responsible for the last block of demand and, therefore, should be allocated the associated emissions.**	Real-time fluctuating value	This methodology prompts grid-based hydrogen producers to adapt their production to the grid's real-time functioning and thus **creates strong incentives for electrolyser flexibility.** To comply with the threshold, producers are forced to monitor real-time grid status and to run their electrolyser only when the grid is fully (or almost fully) decarbonised.

15 Delegated Regulation (EU) 2023/1185 establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels and 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

Figure 3 illustrates how these two regulations interact to assess the certification of electrolytic hydrogen. If the weighted sum of "fully renewable" and "partially renewable" electricity GHG intensities (based on their respective share in electrolyser consumption) exceed the threshold, no hydrogen molecule will be labelled as "renewable". When compliance with the emissions threshold is achieved, "fully renewable" electricity leads to 100% "renewable hydrogen" whilst the share of "renewable hydrogen" stemming from "partially renewable" is based on the share of renewables in the grid two years earlier. It is worth noting then that each time "partially renewable" electricity (from the grid, a non-compliant PPA) is used, not all the produced hydrogen will be labelled "renewable". The remainder is likely to fall under the "low-carbon hydrogen" denomination.

The upcoming low-carbon hydrogen regulation is likely to be heavily shaped by the existing RFNBO rules. In their provisional agreement on the Hydrogen and Decarbonised Gas Market Directive[16], the Council of the European Union and the European Parliament agreed to use the same requirement of 70% GHG emission reduction compared to the fossil fuel comparator for "low-carbon hydrogen", "low-carbon gas" and "low-carbon fuels"[17]. Similarly, the methodologies used for grid electricity carbon intensity calculation laid out in the Delegated Act on greenhouse gas emissions accounting methodology should also apply to low-carbon hydrogen regulation.

Figure 3. Illustration of the compliance with "RFNBO" certification within the EU

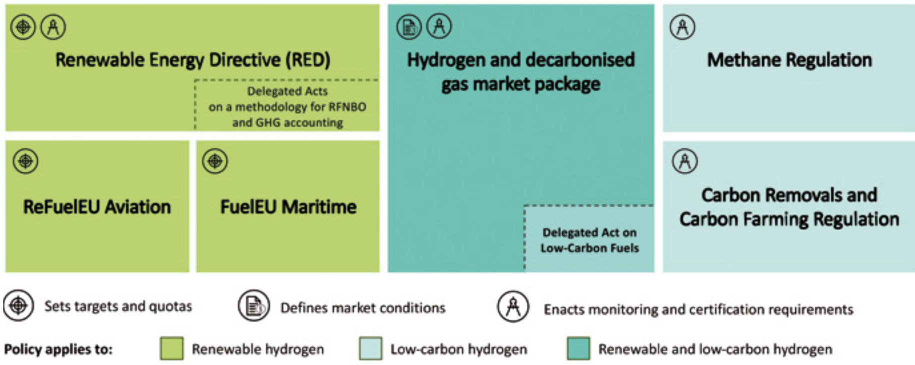


16 Directive (EU) 2024/XXXX of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen

17 See Article 2, points (11) to (13) of the text above.

The low-carbon hydrogen regulation will complement the regulatory framework already set up by existing European Climate Law-related measures (Figure 4). Policies will shape the hydrogen economy and impact hydrogen-related investment decisions. First, RED III, ReFuelEU Aviation Regulation[18] and FuelEU Maritime Regulation[19] set binding targets for RFNBO uptake in industry and transport. This will benefit renewable hydrogen and limit the accessible markets for low-carbon hydrogen. Yet, this will also encourage the installation of electrolysers, which should produce some volumes of low-carbon hydrogen if not supplied at 100% by fully renewable electricity. The regulation impacting the fossil gas-based hydrogen production route should seek consistency with the announced Methane Regulation[20] (which imposes monitoring and reporting of methane emissions as of 2025 and foresees maximum methane intensity values for natural gas placed on the EU's market as of 2029.

Figure 4. Representation of the EU regulatory panorama surrounding hydrogen production



1.3 A methodology to assess the impact of the low-carbon hydrogen regulation

1.3.1 Objective of the study

This report simultaneously aims to quantify the implications of potential variations in the low-carbon hydrogen regulation and to understand the potential developments of the EU hydrogen supply[21]. To achieve this, several case studies are conducted along four different dimensions. The first two dimensions are related to the design of the low-carbon certification scheme, focusing on the grid-based GHG emissions accounting methodologies and setting the emission's threshold. The assessment of the low-carbon hydrogen regulation is complemented by an evaluation of the evolving impact of upstream natural gas emissions.

Moreover, it takes into account the uncertainties around the hydrogen demand levels and quantifies their influence on the competition among supply routes. These four different regulatory and market setups are each evaluated through pairs of assessments. This yields a pool of quantified outlooks used to extract sector-specific insights (discussed in 2) and obtain a comprehensive view of EU hydrogen supply decisions (discussed in 3).

The report aims to contribute to the discussion on the upcoming EU Delegated Act on Low-Carbon Fuels by assessing the impact of regulations on competition between EU hydrogen supply routes. **The objective of this study is to assess different regulatory design parameters of the upcoming regulation to understand its policy implications.** Several case studies are built based on uncertain or dimensioning parameters such as hydrogen demand, availability of technologies, hydrogen level of emission threshold to be considered "low-carbon", or emission accounting methodology.

The case studies are compared to understand the impact of regulatory designs on the four pillars: environmental integrity, industrial competitiveness, the take-off of the European hydrogen economy, and the EU's energy autonomy.

18 Regulation (EU) 2023/2405 of 18 October 2023 on ensuring a level playing field for sustainable air transport

19 Regulation (EU) 2023/1805 of 13 September 2023 on the use of renewable and low-carbon fuels in maritime transport

20 Regulation (EU) 2024/1787 of 13 June 2024 on methane emissions reduction in the energy sector. Further details are available at: EU regulation on methane emissions reduction in the energy sector

21 The emission scope adopted includes lifecycle GHG emissions for the production of hydrogen in coherence with the existing hydrogen regulation. The emissions related to component manufacturing or out of the scope. However, they might be important as highlighted in (de Kleijne et al. 2024).

1.3.2 Overview of the methodology

The modelling framework

The impact of the regulation on the hydrogen market structure is assessed through an optimisation modelling framework representing demand and supply balance of electricity and hydrogen at the country level in the EU, and the tradeflows from potential exporting countries outside the EU.

The modelling framework consists of an electricity market model (Deloitte European Electricity Markets model) coupled with an international hydrogen trade model (Hydrogen Pathway Explorer). The former allows the European future electricity system model, hydrogen production, and exchange to be represented, and the latter introduces hydrogen imports. The modelling allows to comprehensively assess the economics and competition between the different production routes of RFNBO and LCH.

The DEEM model

The DEEM (Deloitte European Electricity Model) is a bottom-up linear optimisation model which provides a granular view of the European power market. It is the power system module of Deloitte's energy system model (DARE – Deloitte Applied Research on Energy Model). It models both the yearly evolution of production capacities and the hourly dispatching amongst installed production units. The model endogenously decides the commissioning or decommissioning of generation units based on cost optimisation. Considering electrical demand, technology production patterns, planned fossil phase-out, cross-border interconnection, and other key European policies (EU-ETS, relevant delegated acts…), the model installs and operates generation capacity to satisfy the electrical demand in each EU country. This gives a granular representation of the electricity system until 2050 with national installed capacities, generation mixes, hourly market prices, as well as associated carbon emissions and fuel consumption.

The model also includes a module dedicated to hydrogen production. Within this module, the installation and operation of electrolysis capacities are optimised alongside the rest of the electrical system to meet the hydrogen demand in each country. Intra-European exchanges are modelled through dedicated hydrogen pipelines. The model makes endogenous decisions in the installation of electrolysers capacity which can then source their electricity from the grid ("grid-based hydrogen") or from dedicated renewable sources, adhering to the conditions outlined in the Delegated Act on a methodology for renewable fuels of non-biological origin. Yet – if deemed more competitive – hydrogen demand can be satisfied through other production routes ("fossil gas-based production" and imports) thanks to the soft-linkage with the Hydrogen Pathway Explorer Model (HyPE).

The HyPE model

The HyPE (Hydrogen Pathway Explorer) model explores the future global hydrogen market by assessing countries outside of Europe's renewable and low-carbon hydrogen production potential and identifying supply and trade patterns to Europe. This approach builds on linear optimisation: the model selects the least expensive way to supply hydrogen demand considering different production routes and transport modalities. As such, the model provides a yearly supply cost curve for each European country, which is later used as an input in DEEM.

Deloitte European Electricity Model (DEEM)

Dare.

DEEM is a tailor-made optimisation model of the European power system meant to satisfy the electrical demand in each country in line with the climate objectives and the economics of the power sector

- **Europe-wide** model at a **nation scale** and with an **hourly granularity** up to 2050
- Optimises the installation and operations of power generation capacities and electrolysers
- Integrates key European policies
- Includes techno-economic data on existing assets, future technology deployments, commodity prices, renewable load factors, etc.

International hydrogen trade model (HyPE)

HyPE is an optimisation model dedicated to explore the future global hydrogen market, by assessing renewable and low-carbon hydrogen production potential and identifying optimal supply and trade patterns matching a given demand outlook

- **Worldwide** model with a **very narrow geographical scale** and **yearly** timesteps
- Optimises the evolution of hydrogen tradeflows towards Europe up to 2050
- Point-to-point hydrogen price curve
- Includes techno-economic data on hydrogen production, conversion/reconversion, transport, and geospatial variables, etc.

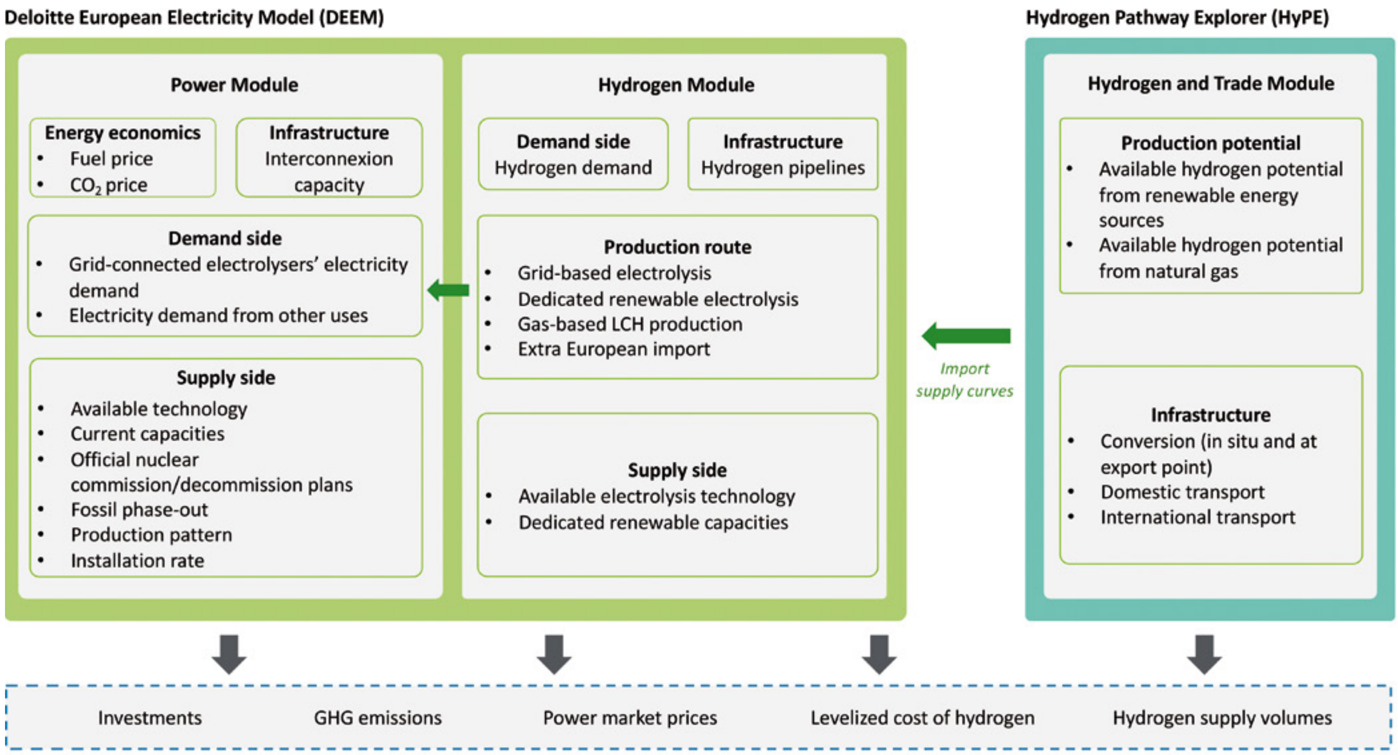
Electrolytic renewable and low-carbon hydrogen production costs and potentials are estimated based on local factors such as wind speed, solar irradiation, land availability, and water access in each country. Production of fossil gas-based LCH results from national natural gas reserves and natural gas consumption and commercialisation trends (in both volumes and prices).

Model coupling

HyPE results directly feed DEEM hydrogen module (Figure 5). This allows a comprehensive representation of the competition between the different hydrogen supply routes. Prices and volumes associated with renewable and low-carbon hydrogen imports from outside of Europe and domestic fossil gas-based production are incorporated as available import options to satisfy European demand in DEEM.

Different modelling set-ups have been used to assess different potential regulatory configurations, hydrogen demand or emissions in upstream natural gas value chains. Through this, potential impacts on supply decisions, production costs, emissions levels and capacity requirements can be assessed accurately. Implications of electrolytic hydrogen production on electricity grids, installation and operation of power production and storage assets are monitored in DEEM. Similarly, the consequences of fossil gas-based hydrogen production on energy autonomy and fossil fuel dependency are quantified in the model.

Figure 5. Illustration of the modelling architecture




H2

2. Low-carbon hydrogen production routes

2.1 Grid-based hydrogen production

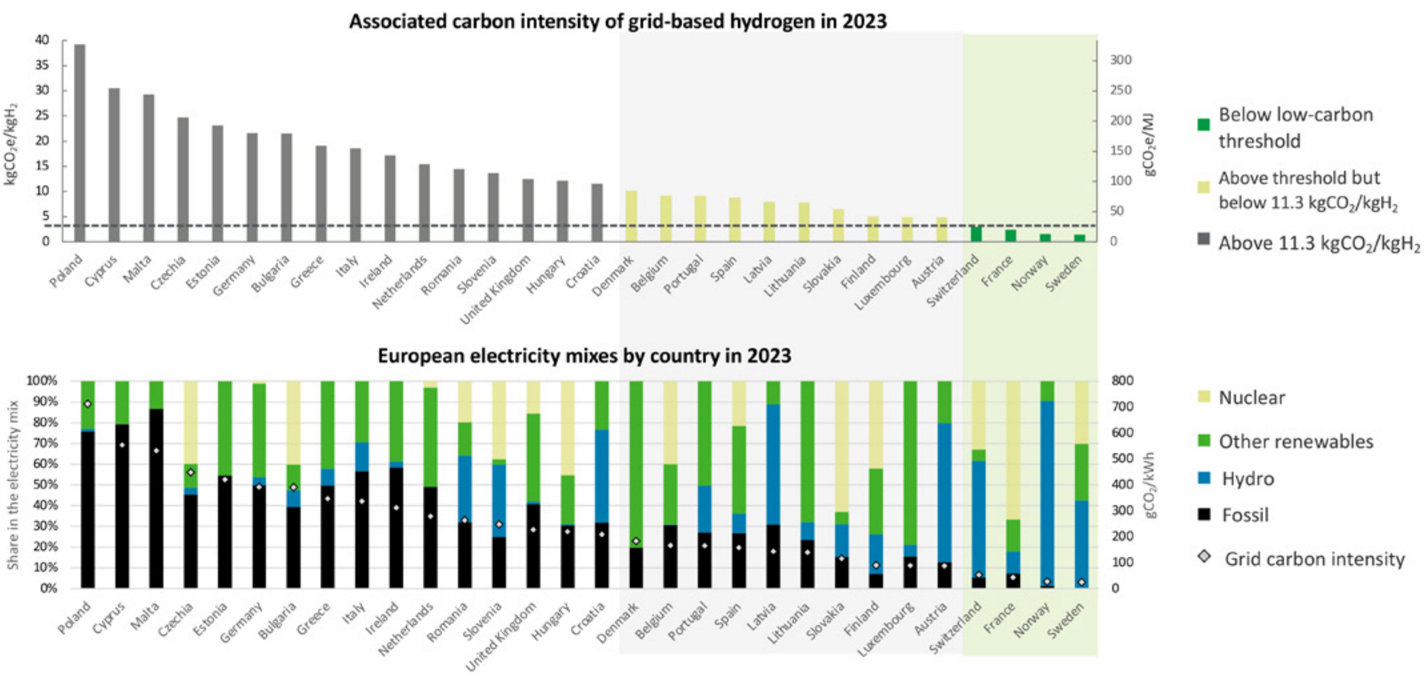
Renewable hydrogen has been at the forefront of the EU hydrogen debates, strategies and policies since 2022. **Grid-based electrolysis presents a compelling option for clean hydrogen production, in both the short- and long-term.** This method offers two advantages over the "fully renewable" route outlined in the Delegated Act on a methodology for renewable fuels of non-biological origin:

- Exempted from time-matching constraints, electrolysers are not forced to match the production pattern of renewables and can achieve higher utilisation factors. This reduces the levelized cost of hydrogen as the CAPEX of electrolysers is spread over a greater amount of output.
- Unlike "fully renewable" projects, grid-based electrolysis does not rely on installing new renewable energy sources. This makes implementation quicker and less complex. In Europe, new renewable energy installation is often hampered by permitting processes that can take several years.

An electrolyser drawing its electricity from the grid while not fully compliant with the Delegated Act on a methodology for renewable fuels of non-biological origin could still produce some RFNBO-certified hydrogen. In accordance with the Delegated Act on greenhouse gas emissions accounting methodology, if the carbon footprint of its production is below the determined threshold (3.38 $kgCO_2eq/kgH_2$) then a share of its production – corresponding to the share of renewables in the mix two years before – would be considered renewable. The upcoming Delegated Act on low-carbon fuels will likely include the rest of the production under the low-carbon category.

Legacy power mixes are paramount in determining the carbon intensity of grid-based hydrogen production in the near term. Resource availabilities, historical investments, and policy decisions created significant national disparities in European generation mixes. This has direct implications for the carbon intensities of existing national grids and the potential for grid-based hydrogen production in the short-term. **The significant differences in starting points among European electricity mixes determine the market opportunities for grid-based LCH production.**

Figure 6. Current European electricity mixes and associated carbon intensity of grid-based hydrogen for an electrolyser with constant operation



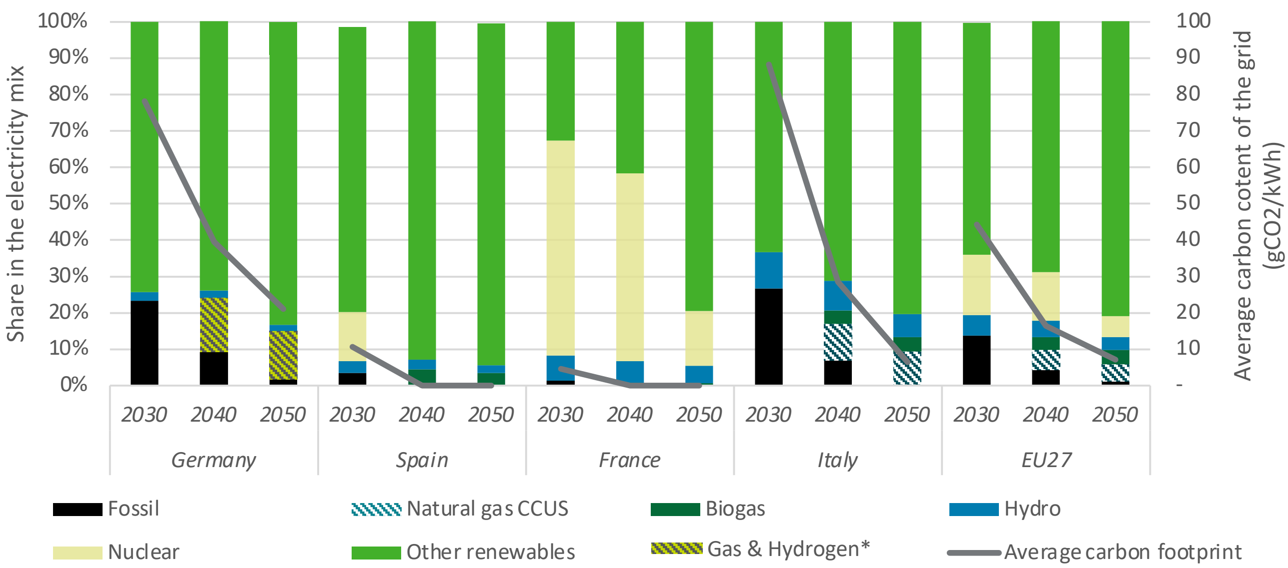
Note: The fossil fuel comparator of 11.3 $kgCO_2eq/kgH_2$ would lead to a carbon intensity of electricity of about 203 gCO_2eq/kWh.

Figure 6 compares the composition of the European power mixes in the year 2023 and the associated carbon content of hydrogen that would be attained by an electrolyser operating continuously and sourcing all its electricity from the respective national grid. Under this setup, only four countries – Sweden, Norway, France and Switzerland – would be able to produce grid-based hydrogen with more than 70% GHG reduction compared to the "fossil fuel comparator", thereby complying with the "low-carbon" and "RFNBO" certification criteria. Reliance on nuclear energy varies across countries– representing around 70% of French production but absent in Norway's grid, while fossil fuels represent less than 7% of the power mix in each of them. In contrast, ten countries (including Austria, Spain, Portugal, Belgium and Denmark) would produce hydrogen with lower GHG intensity than the "fossil fuel comparator" but would not achieve the 70% emissions reduction threshold. Furthermore, in eighteen European countries grid electricity for hydrogen production would result in higher emissions than the fossil fuel comparator.

The carbon intensity of hydrogen produced from national power systems with high shares of fossil fuels can be very high, reaching 19, 22, and 39 $kgCO_2eq/kgH_2$ in Italy, Germany, and Poland. The efficiency losses inherent to power generation and electrolysis make emissions related to electrolytic hydrogen from carbon-intensive power systems higher than those of unabated fossil gas-based hydrogen. This also implies that **whenever grid-based hydrogen production increases fossil power generation, the total emissions within the energy system are higher.**

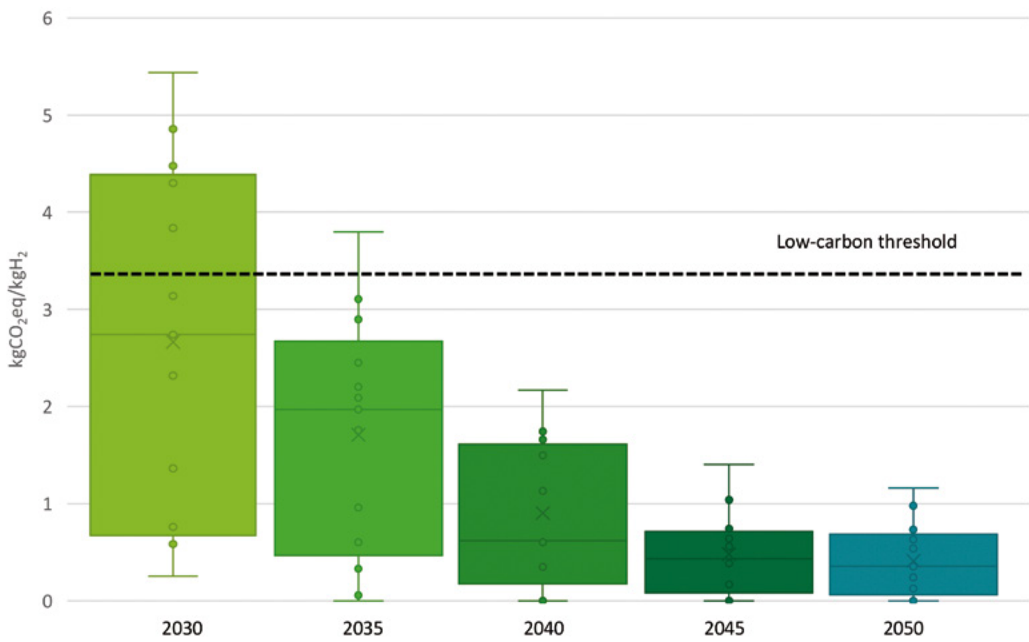
In the future, electricity mixes will evolve by integrating higher shares of renewables, lowering carbon content (Figure 7). In 2030, the carbon intensity of baseload hydrogen production from the power grid is still higher than the threshold in Germany, Italy, Belgium and Poland, with 5, 4.9, 5.1 and 5.3 $kgCO_2eq/kgH_2$ respectively. In 2040 and 2050, the yearly average carbon content is set to fall below 3.38 $kgCO_2eq/kgH_2$ all over Europe (Figure 8), thus enabling grid-based hydrogen production with old and new electrolyser capacity to comply with the threshold easily and thus becoming RFNBO and LCH.

Figure 7. Evolution of the electricity mix and carbon content for selected countries and EU27



** according to Germany Network development plan (Netzentwicklungsplan 2037/2045 (2023) "https://www.netzentwicklungsplan.de"), the thermal power plant fleet in Germany will largely be composed of gas-fired power plants in which climate-neutral hydrogen can be used. Other possible options available for achieving low-carbon power generation such as carbon capture and storage or the use of other climate-neutral gas are discussed.*

Figure 8. Spread and average carbon intensity of the power system in the EU27 towards net-zero in 2050



Box A

Assessing the risk of double-counting renewable power for RFNBO compliance in the yearly average grid emission intensity

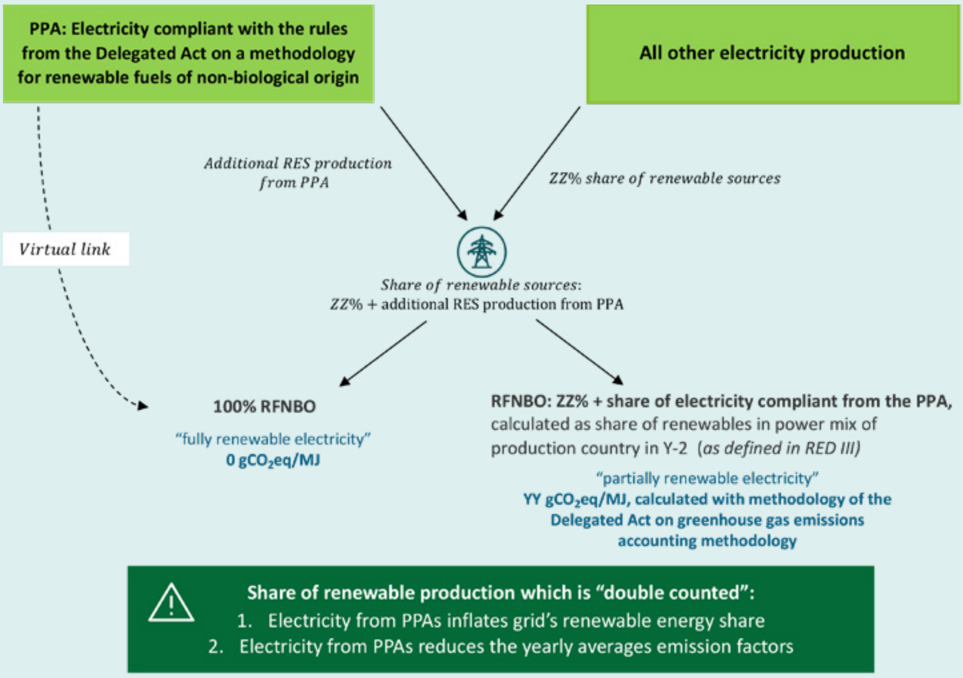
When production of RFNBO-certified hydrogen is based on a renewable energy PPA, the electricity produced from the renewable installation is injected into the grid, and a financial contract is settled between the two parties for withdrawing the power at the location of the electrolyser.

This renewable electricity production leads to renewable hydrogen production through the "fully renewable route". However, it may also facilitate the certification of grid-based production as "renewable" entailing a risk of double-counting:

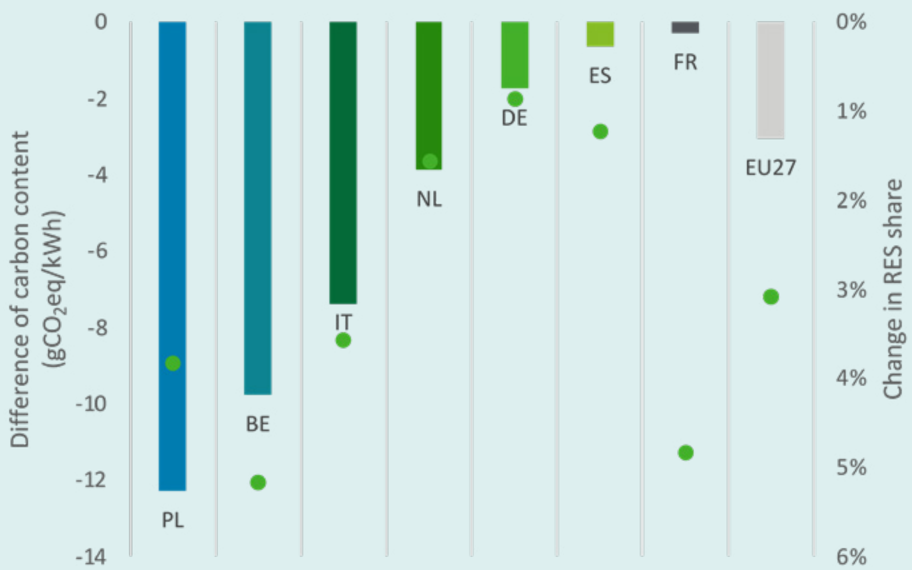
- Hydrogen produced with electricity from the grid can be declared "RFNBO" to a share proportional to the share of renewable energy sources in the mix. Renewable energy PPAs would increase the share of renewables in the grid, leading to a higher share of grid-based hydrogen production certified as RFNBO.
- Similarly, it reduces the average carbon content of the electricity grid, as zero-emission electricity is produced and injected into the grid. Using the "yearly average factors" methodology could then facilitate compliance with the CO_2 threshold.

The following bar chart illustrates the impact of counting electricity produced with a PPA in the total electricity mix and on the yearly average associated carbon intensity compared to a case without any power demand for hydrogen production. The difference between both results in a higher share of renewable electricity production in the yearly average and a lower carbon content of the grid.

Electrolyser producing hydrogen consumed within EU



Impact of counting electricity produced with a PPA for hydrogen production on the total electricity mix and on the yearly average carbon intensity of the mix in selected EU countries in 2030

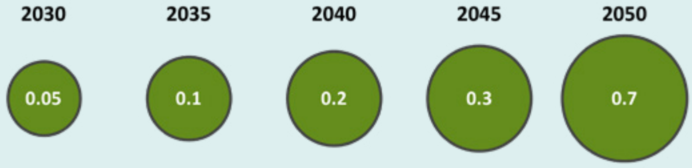


The impact of double counting is two-fold

Electricity from PPAs inflate the grid's renewable energy share for an average of 3% in Europe both in the short-term and the long term, with a variation across countries from 1% (in Germany) to more than 5% (in Belgium). This leads to an additional share of electrolytic hydrogen being certified as RFNBO.

Double counting for the electricity produced by renewables with a signed PPA within the grid decreases average carbon content by 4 gCO_2eq/kWh in 2030 and 0.3 gCO_2eq/kWh in 2050. 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.

Additional grid-based RFNBO (in Mt) in EU27 due to double-counting of renewable electricity



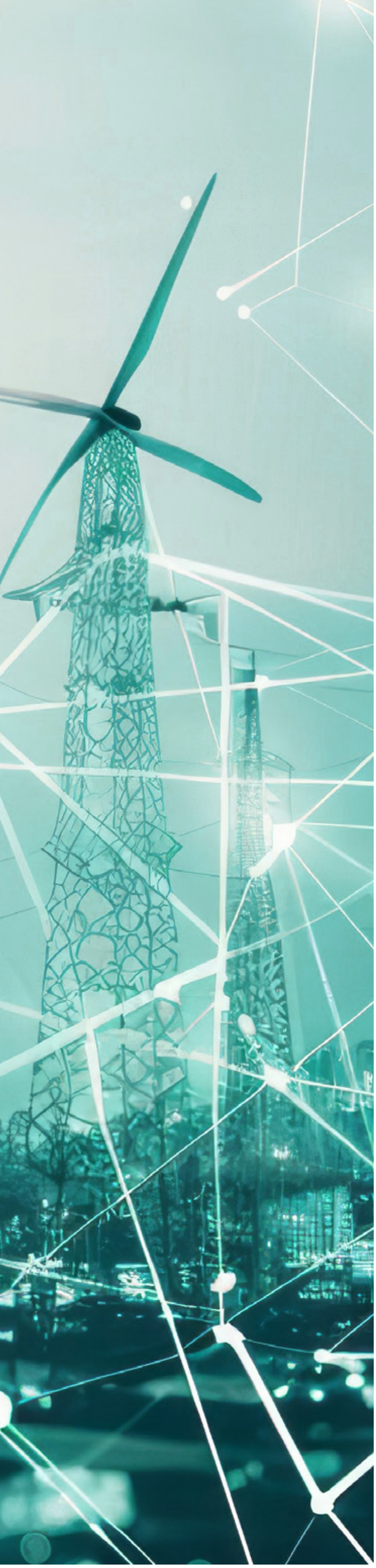
In the end, the impact of double counting RFNBO only happens in countries that are already below the -70% GHG reduction threshold with grid-sourcing electricity, such as France or Spain in 2030. However, from 2040 onwards, when all countries can produce hydrogen from the grid, the risk of double counting increases. In 2030, double-counting renewable electricity leads to less than 0.1 Mt of additional hydrogen that would be labelled as RFNBO, while it reaches 0.7 Mt in 2050. On average, the artificial RFNBO production due to double counting in the EU is about 3% of the total yearly supply.

To avoid double counting, the electricity injected into the grid from signed "fully renewables" PPA should not be included in the calculation of the total share of renewable energy in the mix that serves as a basis for production of RFNBO via grid-sourced electricity. Additionally, this electricity should also be excluded from the computation of the GHG emission intensity of electricity at country level provided by the European Commission accordingly to the Delegated Act on greenhouse gas emissions accounting methodology.

Annual average grid factors provide a static picture which fails to capture the hourly swings in GHG grid intensity. Wind and solar are variable renewable energy sources which provide decarbonised power irregularly. Consequently, with high shares of renewables in the grid, its carbon intensity varies significantly from hour to hour. Whenever meteorological conditions allow for high renewable energy production, the average carbon intensity can be zero. Conversely, when solar and wind production is low, fossil fuel-fired units, which are higher in the merit order, must be called upon, leading to significantly higher emissions. This gap between the lowest GHG-intensive hours and the emission peaks will intensify in the coming years.

As shown in Figure 9, additional renewable energy capacities will lead to many hours of carbon-free electricity production in all European countries. Adding load during these hours would typically not entail any CO_2 emissions. The frequency of these occurrences will depend on the renewable and nuclear installed capacities, as well as the weather conditions and the shape of the load. Those hours would contrast with times of low renewable outputs in which the grid would be forced to rely on fossil fuel technologies, increasing the carbon intensity. Unlike the "yearly average emissions factors" methodology, **an accounting framework based on the marginal unit would enable carbon-free hydrogen production when the grid is clean while preventing electrolysers from running when the CO_2 intensity is high at a given time.** With this methodology, countries with high emission averages could still exploit their hours of carbon-free electricity generation to produce clean hydrogen.

Figure 9. Share of hours of the year with carbon-free electricity production

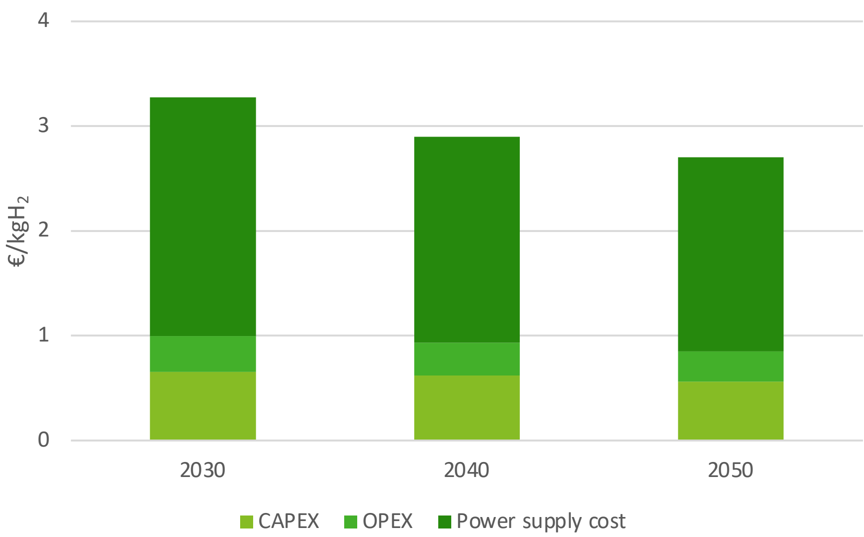


Furthermore, the evolution of power mixes on the pathway to net-zero and, as such, the carbon intensity of the grid, impacts the cost structure of grid-based hydrogen produced in Europe. Regulation and power mixes will directly impact the electrolyser production-to-capacity ratio, measured in full-load hours. This is one of the main parameters affecting the LCOH of electrolytic hydrogen, together with the capital expenditures (CAPEX), operational expenses (OPEX), and the cost of sourcing power from the grid. Whilst CAPEX encompasses the electrolysers stacks purchase and the engineering, procurement and construction costs of the plant, OPEX generally includes the maintenance and equipment replacements. The electricity cost comprises the price of the power used by the electrolyser, which is completed with network tariffs and taxes[22]. The higher volumes produced by running the units for more hours dilute the fixed costs (from an average of 0.66 €/kgH_2 in 2030 to 0.56 in 2050).

OPEX significantly contributes to electrolysers' cost competitiveness. Variations in power prices generate a large spread between grid-based hydrogen production costs across European countries. For example, in 2030 power prices would amount to around 2.78 €/kgH_2 and 1.88 €/kgH_2 in Spanish and French grid-based LCOH, respectively.

Over time, economies of scale, more mature electrolysers technologies and the decarbonisation of European power grids – allowing higher full-load hours – will drive down the share of CAPEX and OPEX of the grid-based hydrogen production. Thus, its LCOH will increasingly be driven by electricity prices, representing most of the expenses. With more renewable capacities coming online in Europe in the coming decades, power prices are also expected to decrease. As a result, grid-based LCOH will follow a downward trend all over Europe as shown in Figure 10. The pace of this reduction, which is crucial for determining the competitiveness of electrolytic low-carbon hydrogen between the different member states, will thus depend on the rate at which they deploy their renewable capacities. Discrepancies will nevertheless remain between countries, although increasingly smaller.

Figure 10. Average LCOH of low-carbon grid-based hydrogen in EU27 countries with a yearly average GHG accounting methodology



22 ACER explains that power to gas facilities in Europe are treated in a similar way to other users regarding withdrawal tariffs (ACER 2021)

2.2 Fossil gas-based hydrogen production

Hydrogen is already today an important resource for EU industry. In 2022, European hydrogen demand stood at 8.2 Mt, primarily used in refineries and for the production of chemicals. This hydrogen was predominantly produced through natural gas reforming. Today, industrial consumers directly produce the hydrogen they consume on-site via Steam Methane Reformers (SMR). This technology splits the natural gas methane molecules, producing hydrogen, but releasing around 9 kilograms of CO_2 for each kilogram of hydrogen. **Cleaner fossil gas-based production can be obtained by equipping the reformers with CCS technologies.** Autothermal Reforming (ATR) is another alternative of fossil gas-based hydrogen production. Compared to SMR, ATR has a better hydrogen yield but requires a more significant initial capital investment and is currently at a relatively lower technology readiness level[23 24].

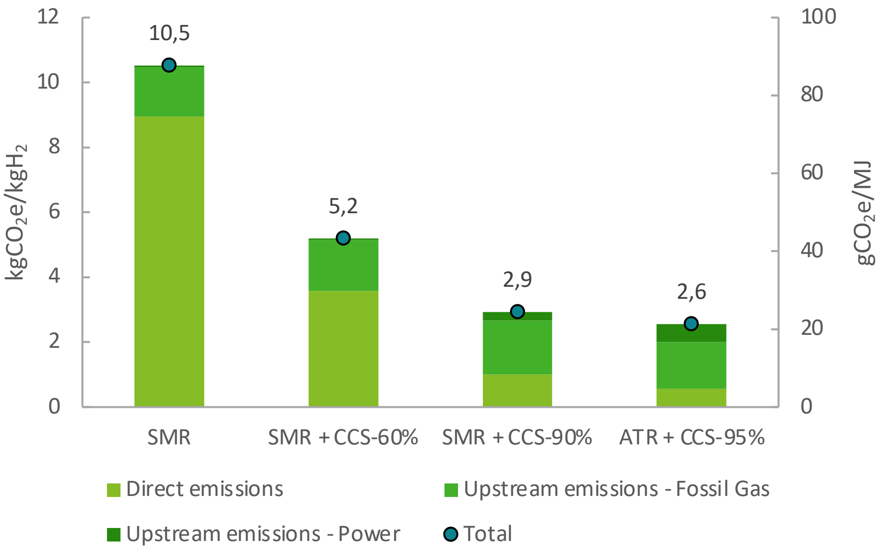
Figure 11 presents the environmental impact of different fossil gas-based hydrogen production options in Europe, calculated using average natural gas emission factors. GHG intensity ranges from 10.5 $kgCO_2eq/kgH_2$ for unabated SMR to 2.6 $kgCO_2eq/kgH_2$ for ATR technologies with high capture rates. **The environmental footprint of the reformers stems from three different origins: direct emissions occurring at the plant's site, emissions related to electricity supply in the upstream and methane emissions during natural gas production and transport.**

Carbon capture technologies can reduce direct emissions but not eliminate them. In an SMR, around 60% of emissions are generated by the feedstock-related use of natural gas (IEA, 2023). These emissions can be captured at a relatively low cost, but more is needed to achieve the required emission reductions below the 70% threshold. Post-combustion capture rates up to 90% could be achieved for SMR, but this would also imply capturing emissions from the flue-gas stream used for heat supply, which requires much more advanced capture techniques. Alternatively, innovative pre-combustion methods are in the early commercial phase and are deemed to achieve 95% capture rates with SMR[25]. In contrast, there is only one CO_2 stream in ATR, which can lead to higher capture rates (potentially up to 95%) with post-combustion techniques. (Ondrey 2022).

The electricity consumption of reformers also entails scope 2 emissions. ATR with CCS has the most significant power consumption (above 2 kWh/kgH_2) which would translate to around additional 0.6 $kgCO_2eq/kgH_2$ assuming the 2022 average EU grid emission factor[26]. Those emissions are expected to decrease as clean technologies gain ground in European power mixes.

Upstream emissions related to the production and transport of natural gas significantly add to the environmental footprint of fossil gas-based hydrogen.

Figure 11. Carbon intensity of different fossil gas-based hydrogen production routes assuming the standard emission factor



Note: The standard emission factor used for the upstream emissions of natural gas is 9.7 gCO_2eq/MJ as proposed in the Delegated Act on greenhouse gas emissions accounting methodology. The standard emissions factor used for the upstream emissions of power consumption is 251 gCO_2eq/kWh based on the 2022 EU average power emission communicated by the European Environment Agency.

23 More information can be found in the IEAGHG Low Carbon Hydrogen from Natural Gas: Global Roadmap report

24 Methane pyrolysis is another promising way of producing LCH from fossil-gas. However, its technology readiness level is lower than that of methane reforming. Its main advantage is that its LCOH can be reduced considerably by selling the solid carbon by-product (also known as "carbon black"). At the same time, to a certain extent, this is a form of Carbon Capture and Use and needs careful consideration regarding the net emission reduction when considering end-of-life emissions of materials produced with it. In addition, methane 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 was used as a feedstock, the carbon intensity of electricity would need to be below EU average to produce hydrogen via pyrolysis that complies with the threshold of 3.38 $kgCO_2eq/kgH_2$ (Hydrogen Europe 2024)

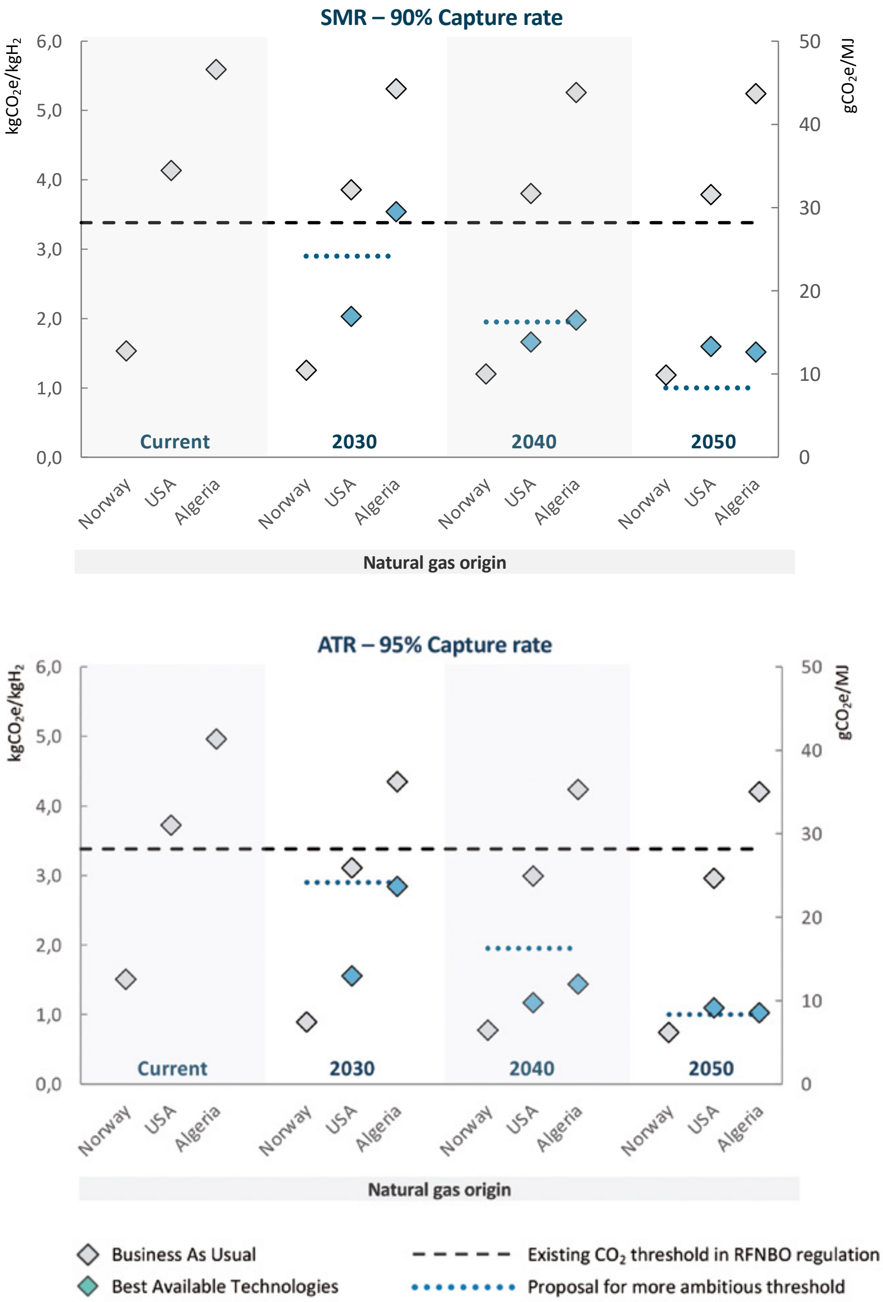
25 In 2022 Wood launched his pre-combustion carbon capture technology targeting SMR. Further information at: https://www.woodplc.com/news/latest-press-releases/2022/wood-launches-next-generation-of-hydrogen-production-technology

26 251 gCO_2eq/kWh, retrieved from European Environment Agency. Available at: Greenhouse gas emission intensity of electricity generation in Europe

Using standard upstream emission factor for natural gas [27] laid out in the Delegated Act on greenhouse gas emissions accounting methodology, the upstream natural gas emissions would amount to 1.4-1.7 $kgCO_2eq/kgH_2$, depending on the technology used (Figure 11).

The standard emission factor suggested in European regulation (and used in Figure 11) does not capture the significant variations in upstream natural gas footprint amongst suppliers and its potential evolution over the coming years. Figure 12 illustrates the carbon intensity of fossil gas-based hydrogen produced in Germany depending on the technology used and the natural gas origin. The performance of piped gas from Norway, Algeria and liquefied natural gas (LNG) from the US are assessed for SMR and ATR equipped with 90 and 95% carbon capture technologies. For Algeria and the US, two values of upstream emissions reflect the current levels Business As Usual and the potential improvement with the adoption of BAT. The carbon footprint of the consumed electricity evolves annually based on the average emission intensity of the German power system[28].

Figure 12. Carbon footprint of fossil gas-based hydrogen produced in Germany as a function of natural gas origin ($kgCO_2eq/kgH_2$)

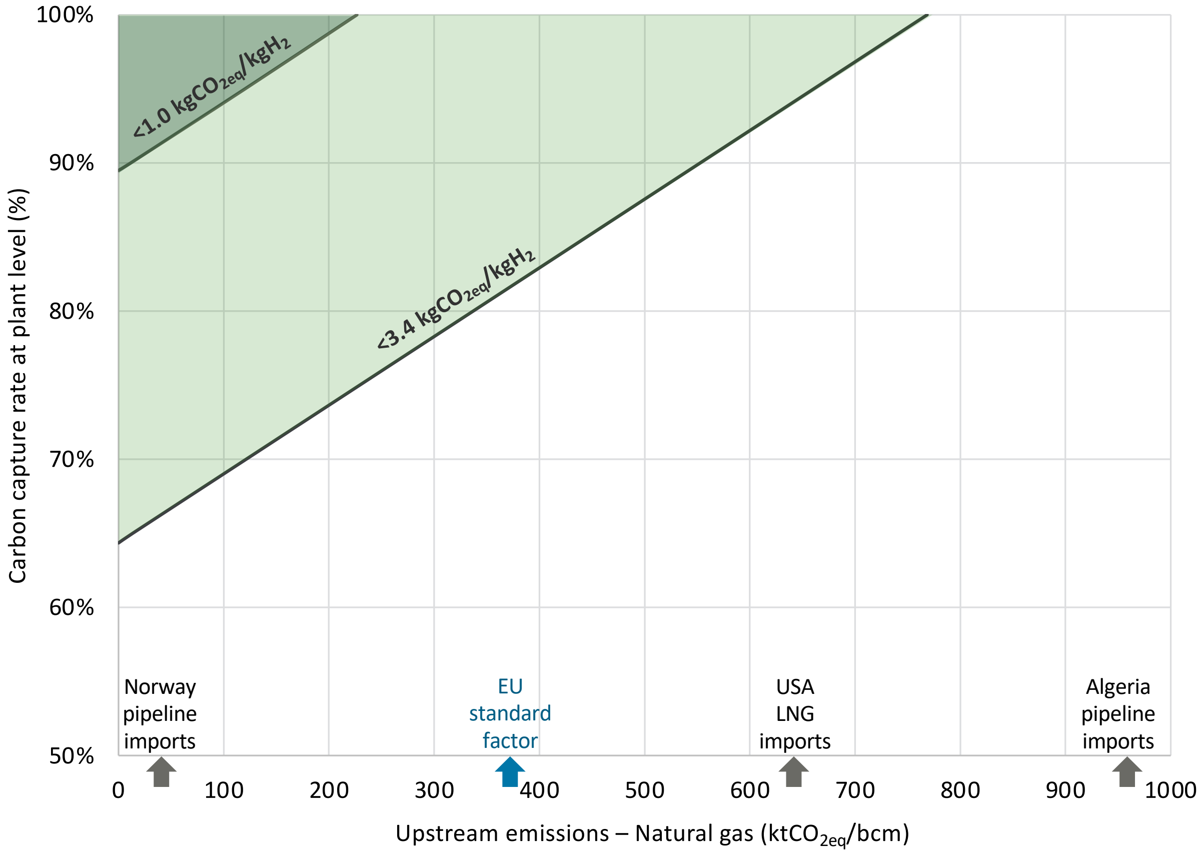


27 9.7 gCO_2eq/MJ, defined in annex B of the Delegated Act on greenhouse gas emissions accounting methodology. Available at: [Delegated Act on greenhouse gas emissions accounting methodology]

28 The carbon intensity of German electricity is calculated with the power-system model DEEM

With current emission factors, producing fossil gas-based hydrogen from Norwegian natural gas in Germany is around 2.5 times less GHG intensive than from United States LNG. If the same installation used Algerian natural gas, the carbon footprint of the produced hydrogen would be increased by more than three. It would not be possible to produce fossil gas-based hydrogen in Germany compliant with the low-carbon emission threshold from Algerian or US natural gas even when using SMR and ATR equipped with the most advanced capture techniques. **The origin of natural gas has a crucial impact on the carbon footprint of natural gas-based hydrogen. CO_2 and methane emissions from gas production and transport should be closely monitored to ensure compliance with the emissions thresholds.** In particular, assuming the European Commission standard upstream emission factor for natural gas would lead to a misestimation of the CO_2 capture rates needed to make the project compliant with the emission threshold (Figure 13).

Figure 13. Required CO_2 capture rates and upstream emissions for fossil gas-based LCH production to meet emissions thresholds



Note: Scope 2 emissions linked to reformers electricity consumption are not included in this chart. These emissions would push the areas upward and are dependent on the carbon intensity of the electricity used. The emissions factors from Norwegian, US and Algerian supply are drawn from (Carbon Limits, 2024) and comprise methane and CO_2 emissions. For natural gas, a standard calorific value of 40 MJ/bcm has been used based on ISO 13443.

Adopting BAT to reduce emissions in the natural gas value chain can minimise hydrogen carbon footprint by up to 75% (Carbon Limits, 2024). Assuming emission factors of BAT, it becomes possible to produce "low-carbon" fossil gas-based hydrogen in Germany using natural gas from Algeria and the US by 2030[29]. If improvements continue beyond 2030, it might be possible to produce fossil gas-based LCH with a carbon intensity close to 1 $kgCO_2eq/kgH_2$ in all the cases assessed. **The low-carbon hydrogen regulation should incentivise the adoption of BAT in natural gas supply chains consistent with the EU Methane Regulation.**

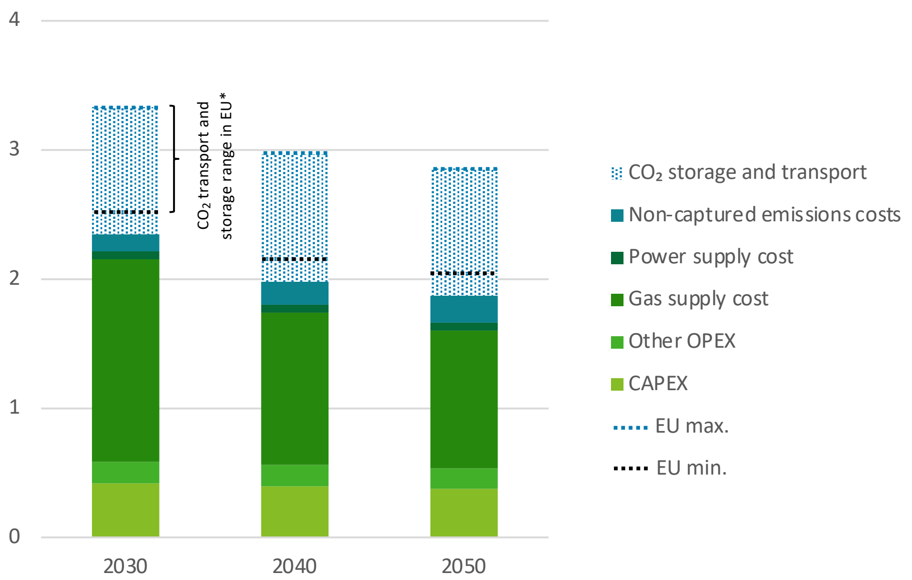
With fewer unabated emissions and smaller natural gas consumption, the ATR+CCS production route ultimately has a lower carbon footprint than the SMR+CCS technology. **Establishing the low-carbon hydrogen regulation—particularly the setting of the emissions threshold—could shift investment preferences between these two technologies.**

The cost of producing fossil gas-based hydrogen is usually affected by several factors, with fuel prices and CAPEX being the most significant. In the case of fossil gas-based hydrogen production, the CO_2 capture, transportation and storage costs add up to the LCOH. Figure 14 shows the different cost components and the range of transportation and storage costs. CO_2 transport costs vary by country they depend on the distance from the CO_2 production and storage sites, the flow rates considered and the type of sites[30]. It should be noted that significant uncertainties remain regarding the development of the CO_2 transportation and storage infrastructure in Europe, and the EU still lacks commercially proven geological CO_2 storage capacity.

The EU ETS would hardly impact the cost of fossil gas-based LCH. Since most of the emissions associated with fossil gas-based LCH occur during natural gas production and transport, they are not covered by the scheme outside of the EU[31]. Only the residual direct emissions after capture are subject to the ETS allowance, representing barely 0.20 €/kgH_2 if the CO_2 price hits 200 €/tCO_2eq.

The main driver of the competitiveness of fossil gas-based LCH is the feedstock costs. The price of natural gas is expected to account for 40 to 55% of the LCOH in 2040. Thus, **uncertainties about future natural gas price developments increase the market risks for fossil gas-based hydrogen projects.** Additionally, natural gas-importing regions like the EU will have a cost disadvantage compared to natural gas producers like the Middle East and North America.

Figure 14. Breakdown of fossil gas-based hydrogen costs in Europe (SMR with 90% CCS)



** The range of CO_2 storage and transport costs varies from country to country, primarily depending on the distance to the storage location.*

Note: On-site LCOH estimate. Most notably, a natural gas price of 33€/MWhLHV, 25 €/MWhLHV and 22 €/MWhLHV is assumed in 2030, 2040 and 2050 respectively. CO_2 storage and transport costs vary from country to country, primarily depending on the distance from the reformer's location to the storage site. Further details on the assumptions are detailed in Appendix A.4.

29 If the CO_2 infrastructure and regulations allow it

30 The storage site considered is an offshore site, in the North Sea. It's the same one used here on JRC report Shaping the future CO_2 transport network for Europe

31 The scope of the Carbon Border Adjustment Mechanism (CBAM) encompasses the hydrogen sector but does not include the natural gas sector. The CBAM thus applies to hydrogen and hydrogen derivatives imports but not to natural gas imports, even if these latter are used to produce fossil gas-based hydrogen. Moreover, the CBAM only concerns direct emissions. Therefore, upstream and transport emissions of natural gas will not be taxed, neither for fossil gas-based hydrogen produced in the EU nor for imported fossil gas-based hydrogen. More information can be found in the 14th EU ETS Compliance Conference

Figure 15 shows the 2040 LCOH for fossil gas-based LCH in various European countries for different average gas prices[32]. Depending on the country, an increase of 15 €/MWh to 40 €/MWh in the average gas supply cost leads to an LCOH increase of 50% to nearly 70%.

The costs of fossil gas-based LCH presented in Figure 15 assume that CO_2 can only be stored offshore in the North Sea. However, the development of CO_2 storage and transportation infrastructure in Europe still faces many uncertainties, and relying on offshore sites is one of many possibilities for storing captured CO_2. The heat map in Figure 16 shows the LCOH ranges for different CO_2 storage options.

Onshore sites are storage locations within the country where fossil gas-based LCH is produced. Since CO_2 needs to be transported over a shorter distance and onshore storage costs are expected to be lower, this solution is less expensive than offshore storage. However, it is essential to note that this is a more uncertain solution than offshore storage (for instance, onshore CO_2 storage is currently banned in Germany). Another possibility is to use the captured CO_2 on-site. In this case, no cost is associated with storing and transporting CO_2 (only capture). Still, fossil gas-based LCH production must be located on an industrial site, and depending on the use, carbon utilised might not be considered a permanent storage option.

Investment decisions in fossil gas-based hydrogen production assets would have implications beyond the economic spectrum. Russia's invasion of Ukraine and the subsequent energy crisis highlighted the economic and political consequences of fossil fuel import dependencies. To foster energy independence, system resiliency, sovereignty and protect final consumers from possible shortages, the EU aims to minimise and diversify its gas imports. Increased reliance on natural gas to produce hydrogen would counter this effort. Thus, the Delegated Act on Low-Carbon Fuels has a role to play in ensuring diversity of production and avoiding strengthening existing gas dependencies to align with this vision.

Figure 15. Heat-map of natural gas price impact on fossil gas-based LCOH for different European countries (SMR with 90% CCS) – 2040

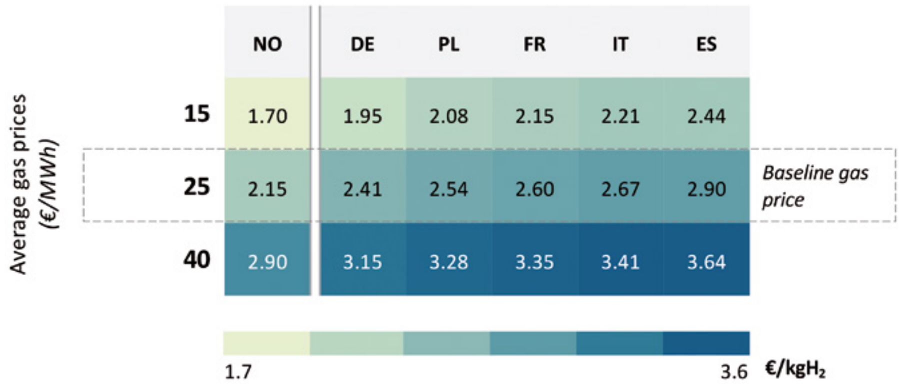
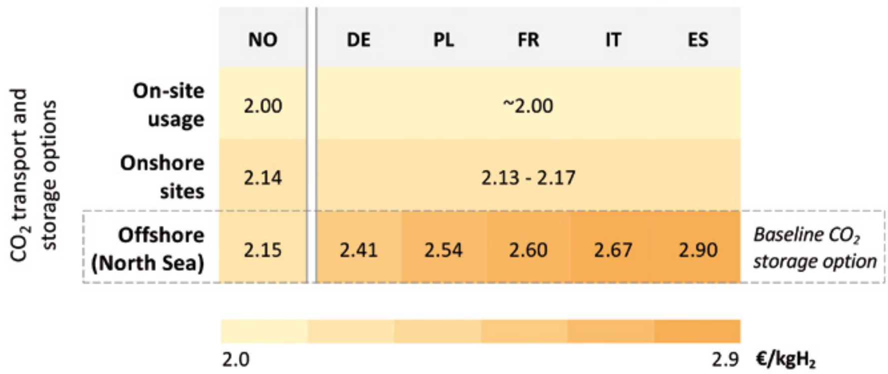


Figure 16. Heat-map of CO_2 storage option impact on fossil gas-based LCOH for different European countries (SMR with 90% CCS) – 2040



32 This analysis is based on offshore storage in the North Sea for captured CO_2

Box B
Discussing the compliance and competitiveness of co-processing if "offsetting" is allowed

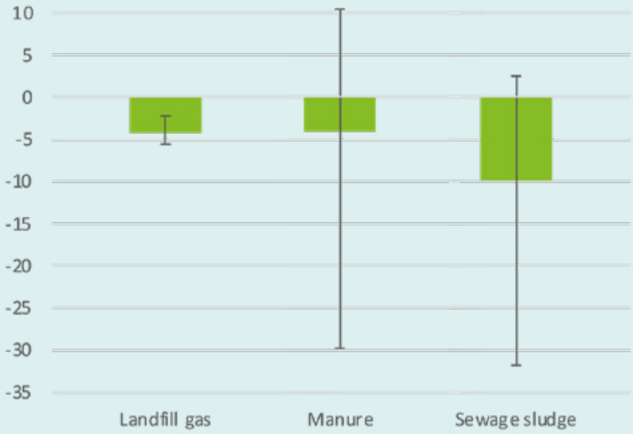
Biomethane could replace natural gas in hydrogen production, significantly reducing lifecycle emissions. Biomethane, or "renewable natural gas, " comes from upgrading biogas produced from organic matter such as manure, sewage sludge, maize or landfill gas. Chemically similar to fossil natural gas, it can be used as a feedstock to produce hydrogen through the steam methane reforming process. In this case, the carbon intensity of hydrogen production is significantly lower than that of conventional processes using natural gas—and can sometimes even be negative (see the following figure on LCA GHG emission footprint).

According to the ICCT methodology (Zhou et al. 2022) and consistent with JRC's Well-to-Tank analysis (European Commission. Joint Research Centre. 2020), depending on the emission accounting methodology, biomethane can potentially have a negative emission factor. Potential negative emissions (even without CCS) can lead to substantial offsetting opportunities, depending on the accounting rules in place. According to the EU Carbon Removals and Carbon Farming (CRCF) regulation proposal[33], carbon removals should not cause significant harm to the environment. However, the regulation does not specify guidelines for gases-blendings to deal with GHG accounting and removal certification when involving those with negative emissions, such as biomethane, with natural gas. This omission could hinder further efforts to reduce natural gas emissions from hydrogen production by allowing these emissions to be 'offset' through blending.

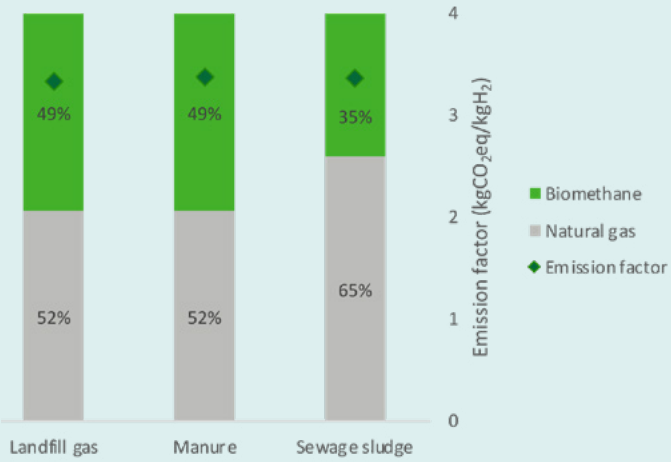
Using 100% biomethane for hydrogen production is unlikely to be cost-competitive. However, a blend of biomethane and fossil natural gas might be interesting for a facility to certify its production as renewable and "virtually" low-carbon. Depending on the proportions of each gas, it is possible to produce hydrogen below the 3.38 $kgCO_2eq/kgH_2$ threshold while relying at 52 to 65% on unabated fossil gas. The natural gas/biomethane blends leading to produced hydrogen to be at the threshold depend on the origin of biomathane as shown in the chart on the right-hand side.

In 2030, hydrogen production costs from blended gas could range from 3.4 €/kgH_2 (for biomethane from landfill gas) to 10.5 €/kgH_2 (for biomethane from manure). The lower side of this range would be cost-competitive with the other hydrogen production routes. Thus, if the regulation allows it, some hydrogen producers will likely opt for SMR with a blended gas process over others. This would have several undesirable effects. First, producing hydrogen with a high proportion of natural gas will be possible, which would

LCA GHG footprint of hydrogen produced from biomethane of different origins



A blend of natural gas/biomethane to produce LCH and emission factor



not help reduce the EU's dependency on natural gas imports. Second, despite the alternatives, this would divert part of the biogas production to hydrogen. Projections already estimate that its supply will be non-negligible but limited compared with current natural gas demand levels[34] (IEA 2023b; Guidehouse 2022a; IEA 2020), and better usage of these scarce resources could be done in other sectors.

33 Proposal 2022/0394 (COD) for a regulation establishing a Union certification framework for permanent carbon removals, carbon farming and carbon storage in products. A provisional agreement has been reached by the European Parliament on 10 April 2024

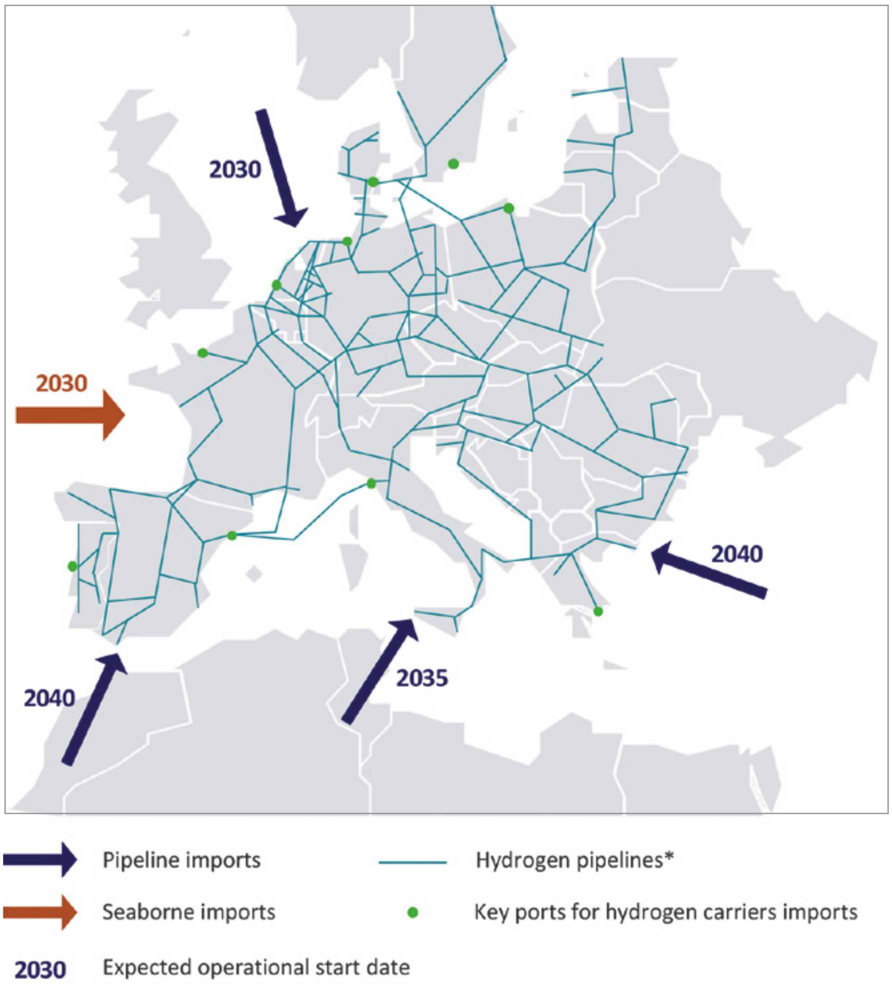
34 About 10% of current natural gas demand in the EU by 2030 (Guidehouse 2022a)

2.3 Hydrogen imports

By setting ambitious targets for renewable hydrogen supply in 2030 and beyond in its REPowerEU plan, **the European Commission opened the doors widely to clean hydrogen imports** acknowledging that renewable resources would be subject to intense sectoral competition and deployment hurdles. Concurrently, several international players have issued or prepared hydrogen strategies and roadmaps with the intent to position themselves as global exporters. They seek to capitalise on large renewable endowments and/or abundant natural gas reserves. Norway and nearby countries from North Africa or the Caspian region could address part of the EU's low-carbon hydrogen demand at competitive prices via pipelines. Thanks to ammonia shipping, more distant suppliers from the Middle East and North America may have a prominent role as well. Against this backdrop, EU countries might be incentivised to supplement domestic production with clean hydrogen imports.

Hydrogen trade flows towards and within the EU will to a large extent be shaped by infrastructure development (Figure 17). A robust network of pipelines connecting EU countries together and with low-cost exporters has been planned as part of the "Hydrogen Backbone" project. The numerous hydrogen pipeline projects recently announced are at different stages of development[35] and infrastructure roll-out will likely be phased in over more than ten years. Connections between Germany and its close neighbours – notably Norway – should be in place by 2030. Southern corridors should emerge sometime after. Italy would be connected to Tunisia and Algeria by 2035 whilst the connection between Spain and Morocco would be ready by 2040. In parallel, expansion of ports facilities would allow greater ammonia imports. New transport infrastructure unlock trade opportunities lowering the cost of supply in importing regions and creating economic opportunities for exporters.

Figure 17. Illustration of modelled hydrogen trade infrastructure



** As of 2040, based on data from ENTSOG and European Hydrogen Backbone*

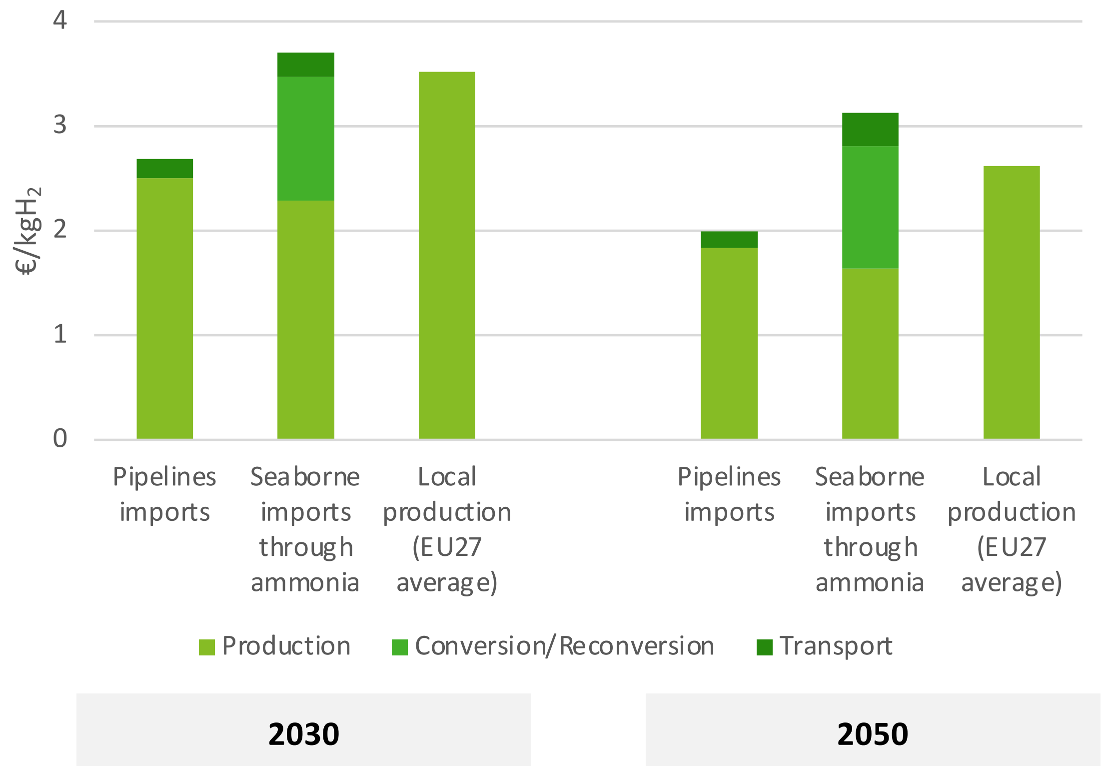
35 European Hydrogen Backbone Maps, European Hydrogen Backbone

Both gas exporters and countries with high renewable endowments would be able to leverage their energy resources to produce hydrogen at a cost well below the European average. Indeed, hydrogen production costs in potential international suppliers are 28-40% below average EU LCOH in 2030 and 20-44% in 2050 (Figure 18). **However, additional supply chain costs – conversion, transportation, storage, re-conversion – may significantly affect European landed costs.** In that regard, countries that have the option to export gaseous hydrogen via pipelines (particularly if repurposed) have a significant advantage over those that must use the sea.

Indeed, pipelines transportation costs are about 0.1-0.3 €/kgH_2 whereas the more complex logistics of maritime imports incurs notably higher supply chain costs (1.3-1.6 €/kgH_2). Yet, even with additional costs linked with conversion, transportation, offloading and re-conversion for ammonia, the end-user cost could still be more advantageous for many European manufacturers compared to local unsubsidised production. Besides, existing and planned ammonia import infrastructure in ports could allow industrial hubs to address their supply gaps.

The scope of the Delegated Act on a methodology for renewable fuels of non-biological origin, that of the Delegated Act on greenhouse gas emissions accounting methodology, and that of the upcoming Delegated Act on Low-Carbon Fuels encompass the hydrogen consumed in the EU regardless of its origins. **International suppliers will hence face the same constraints regarding grid carbon content and natural gas upstream emissions when producing low-carbon hydrogen.** Consequently, the design of the Delegated Act on Low-Carbon Fuels will also shape the EU's reliance on hydrogen imports.

Figure 18. Comparison of landed cost of hydrogen supply in Europe for pipelines and seaborne imports and local production



3. The impact of regulation on hydrogen market structure

3.1 Methods to account for CO_2 emissions of grid-connected electrolysers

The Delegated Act on greenhouse gas emissions accounting methodology outlines strict rules for electrolysers to comply with for considering electricity as fully renewable (i.e. additionality criteria, temporal and geographical correlation), and proposes three parallel accounting rules to compute the greenhouse gas savings from fuels of non-biological origin produced from electricity coming from the power grid (Figure 19) those are:

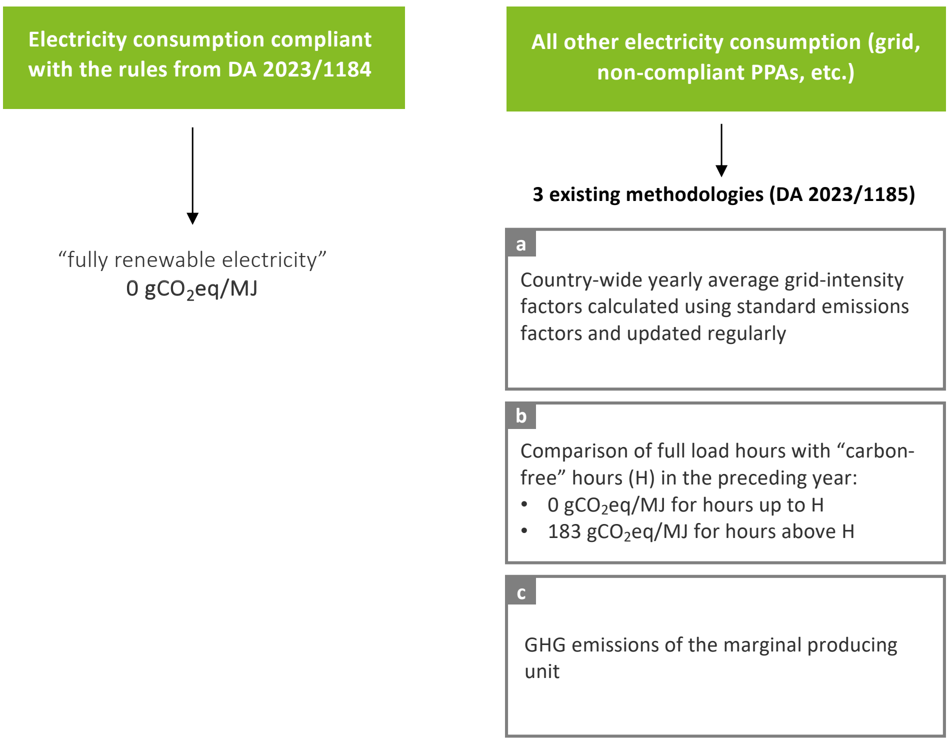
a. The first method proposes country-specific average grid-intensity factors. It is a single pre-determined yearly value based on the previous year's power mix and its associated carbon intensity. Thus, a single GHG value is assigned to the electricity consumed from the grid.

b. The second method is based on the number of hours in the previous year when the price was set by an installation producing renewable or nuclear electricity. For calculating the emission footprint of consumed electricity in the current year, these hours should be counted as 0 gCO_2eq/MJ, while the remaining hours should be assigned an emission factor of 183 gCO_2eq/MJ.

c. The third method considers real-time monitoring of the dispatching of power plants. The carbon intensity of the grid is then set by the carbon intensity of the last unit dispatched to meet the demand, the marginal unit.

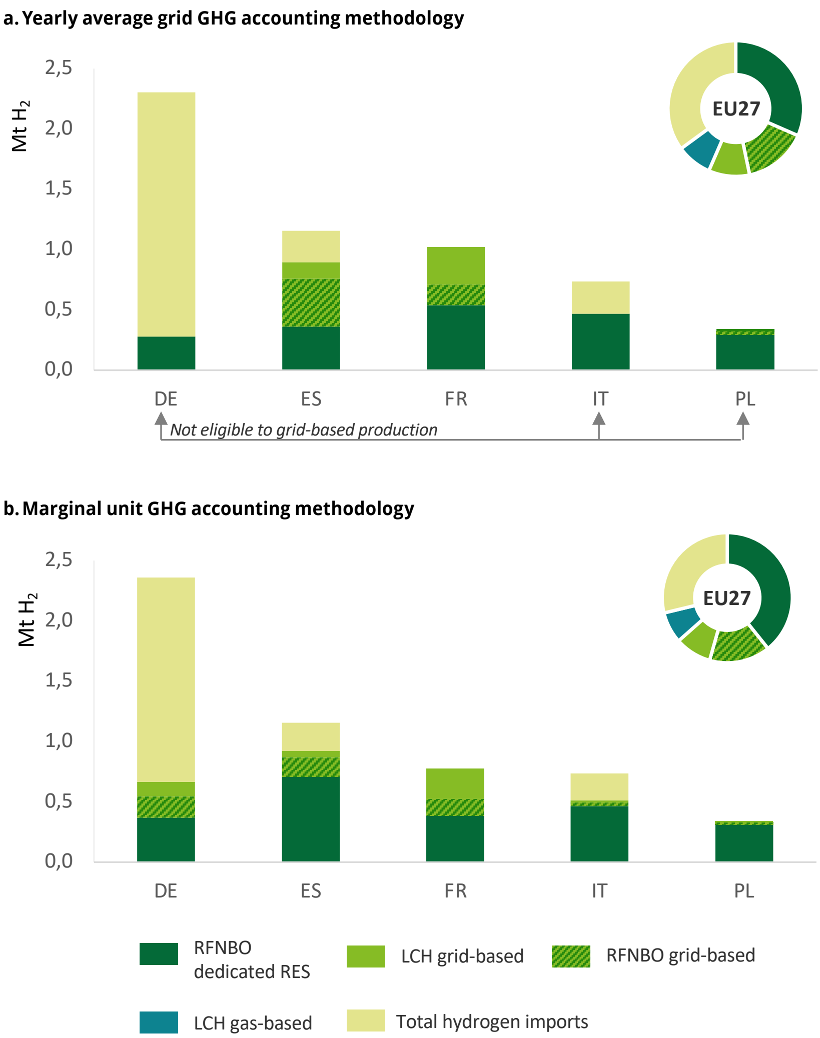
The three approaches imply varying levels of simplicity in terms of monitoring and certification procedures and perform differently in terms of information accuracy. The first method relies on static yearly average values, providing predictability, ease of planning, and administrative efficiency but lacks signalling of the real-time operations of the power system. In contrast, the third method employs dynamic real-time values that accurately reflect the grid conditions at any given moment. While the yearly average method is simpler and less demanding administratively, the marginal unit method offers a more accurate representation of the system's actual GHG emissions, albeit with increased complexity and data requirements. Method b) falls in between as fixed past-year values to obtain the present-year zero GHG budget hours.

Figure 19. CO_2 accounting methodologies from the RFNBO's Delegated Act



Simplicity and consistency in regulation is valuable. Aligning the GHG emissions accounting methodologies for the Delegated Act on Low-Carbon Fuels with those established in the Delegated Act on greenhouse gas emissions accounting methodology is vital. Adopting a unified approach ensures a streamlined and coherent framework to ease reporting and compliance for stakeholders. Producers will likely produce both, LCH and RFNBO, with the same grid-connected units. This alignment simplifies administrative processes and enhances the comparability and transparency of GHG emissions across different types of products. It gives regulatory clarity with clear guidelines and a predictable regulatory environment.

Figure 20. Grid-based LCH production in 2030 with different GHG accounting methodologies

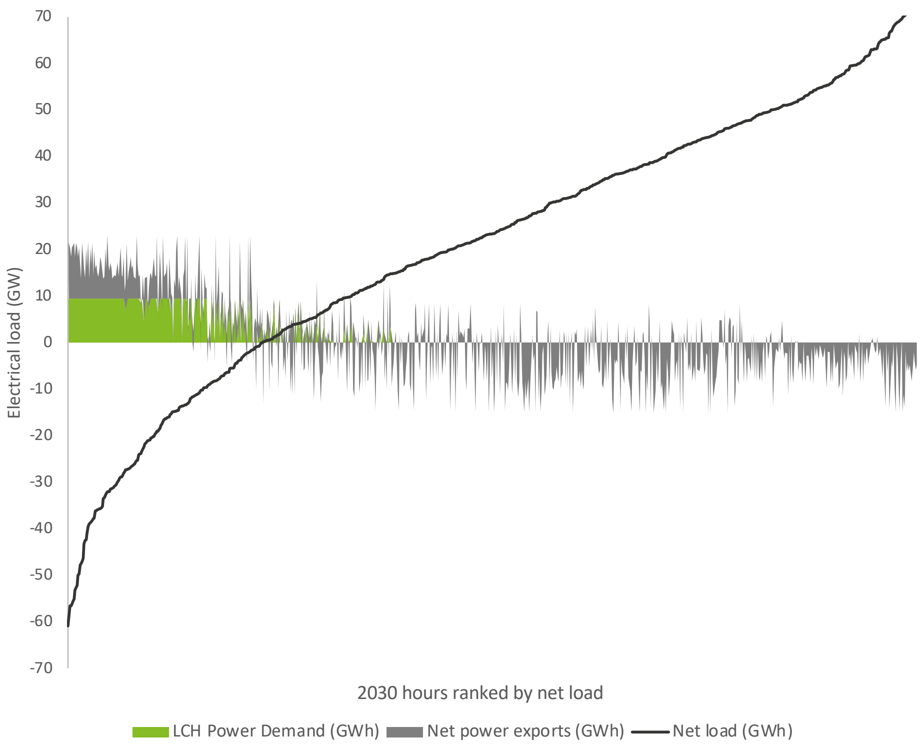


The hourly marginal GHG emissions accounting methodology supposes the GHG emissions of the marginal unit producing electricity to the grid is the one setting the carbon content of the hydrogen produced. This methodology enables the use of electrolysers when the share of low-carbon sources in the electricity mix is high.

The marginal unit GHG accounting methodology accelerates the production of electrolytic LCH and RFNBO. It enables countries to produce grid-based hydrogen below the threshold earlier than if assuming yearly average GHG emissions. During mild sunny springs/summer periods, when renewables and low-carbon electricity exceed the electricity load, grid-connected electrolysers can deliver LCH and RFNBO even if the yearly average CO_2 intensity of the mix is still higher than the threshold. As an illustration, Figure 20 presents country-specific and EU27 differences with the two opposed methodologies in 2030. The marginal unit accounting methodology allows countries like Germany, Italy, Poland or Belgium to leverage their "carbon-free" hours by producing grid-based LCH as soon as 2030. In contrast, they would be prevented from doing so with the yearly average methodology. Consequently, France and Spain reduce their grid-based hydrogen output, compared to the yearly average methodology, since they export less hydrogen via pipelines to their neighbours that can produce grid-based LCH and RFNBO earlier. Overall, in 2030, the marginal unit GHG accounting would allow for 63% of the demand to be met through electrolytic hydrogen, in comparison with 57% if the yearly average accounting was adopted. This additional domestic supply would lead to a corresponding 6-percentage point decrease in import shares by 2030 (Table 2).

The marginal unit GHG accounting enables grid-connected electrolysers to contribute with the provision of system flexibility to accommodate variable solar and wind generation. Figure 21 shows the flexibility of grid-connected electrolysers depending on the net load of the considered country[36]. When the net load is positive, demand is higher than renewable generation and thus must be met via import from other countries, fossil production or discharge of storage units. When net load is negative, i.e., generation is higher than demand, the country exports its excess electricity or charges its storage units. Without any power demand for hydrogen production, the remaining surplus is curtailed, leading to a loss for the system and inefficient operation. However, in a conducive environment, this surplus could partly be absorbed by electrolysers. The hydrogen then produced is both clean and cost-effective as this coincides with hours of fully renewable production and low electricity prices. Some hydrogen production can still be observed during hours of positive net loads. Those extra hours of hydrogen production improve the business case of grid-connected electrolysers, yet they remain infrequent as the accounting methodology disincentivises production when net loads are positive. Compared to the rigid yearly average methodology, the hourly marginal methodology provides signals for electrolysers to operate in a flexible manner – for a better alignment between their dispatch and the system needs. As shown in Table 2, this allows the integration of 15 GW of additional renewable capacity with the development of 19 GW additional electrolysers in 2030.

Figure 21. Germany's 2030 grid-based hydrogen production pattern and net load with marginal unit GHG accounting methodology



The emission accounting methodology based on yearly averages hinders the potential for system-friendly operations of grid-connected electrolysers. The yearly-average-based methodologies (methodologies a. and b) lead to decorrelations between hydrogen production and the dynamics of the power system. By not incentivising the use of electricity from the grid during hours when carbon emissions are low, the opportunity to maximise CO_2 emission savings is missed. When electrolysers can modulate their operations, they take advantage of cleaner electricity, resulting in greater reductions in carbon emissions. The lack of flexibility ultimately leads to reduced CO_2 emission savings that could potentially be achieved. By assuming the static threshold, fully adopting the marginal unit methodology would induce an additional 29 $MtCO_2eq$ savings, cumulated until 2050 (Table 2).

36 The net load is calculated as the difference between power demand (excluding hydrogen production) and the electricity production of renewable sources (solar, offshore and onshore wind)

The advantages and costs of adopting a more sophisticated methodology against a simpler static one should be put on balances. The hourly monitoring and dispatch of the electricity carbon intensity to dispatch electrolysers could be a barrier for small producers which could delay the development of the industry. Moreover, the adoption of the hourly marginal methodology leads to higher amounts of renewables and electrolysers installed capacity, which might cause difficulties in keeping up with the pace of deployment.

3.2 A market structure robust to variations in demand

Hydrogen production costs vary markedly by production technology across countries, both over the course of a given year and over larger timescales. In a given year, these variations are influenced by fluctuations in natural gas and electricity prices, weather conditions, and infrastructure availability. Over multiple years, evolution of technology costs and transformation of electricity grids would impact the LCOH.

Figure 22, Figure 23, Figure 24 and Figure 25 present the evolution of hydrogen supply costs between 2030 and 2050 respectively for RFNBO production, grid-based LCH production, fossil gas-based LCH production, and LCH imports. Ranges for all production options are very wide across Europe and significant overlap exists between the different production technologies. As such, there is no single dominant EU-wide technology. Country differences in terms of legacy power mixes, meteorological conditions and access to CO_2 storage sites will shift the competitiveness of the different technologies.

Table 2. Performance comparison between carbon accounting methodologies assuming a fixed GHG emissions threshold

	Methodology for emission accounting: a) Yearly average	Methodology for emission accounting: c) Hourly marginal
Installed renewable capacity*	2030: – 2050: –	2030: **+15 GW** 2050: **+31 GW**
Installed electrolyser capacity	2030: 44 GW 2050: 290 GW	2030: **63 GW** 2050: **310 GW**
Share of hydrogen imports	2030: **35%** 2050: 14%	2030: 29% 2050: **15%**
Avoided emissions*	2030: – 2050: – Cumulative (2030-2050): –	2030: **-6 $MtCO_2eq$** 2050: **-1 $MtCO_2eq$** Cumulative (2030-2050): **-29 $MtCO_2eq$**

*Compared to yearly average methodology

Figure 22. Evolution of LCOH over time for RFNBO production using dedicated renewable energy sources

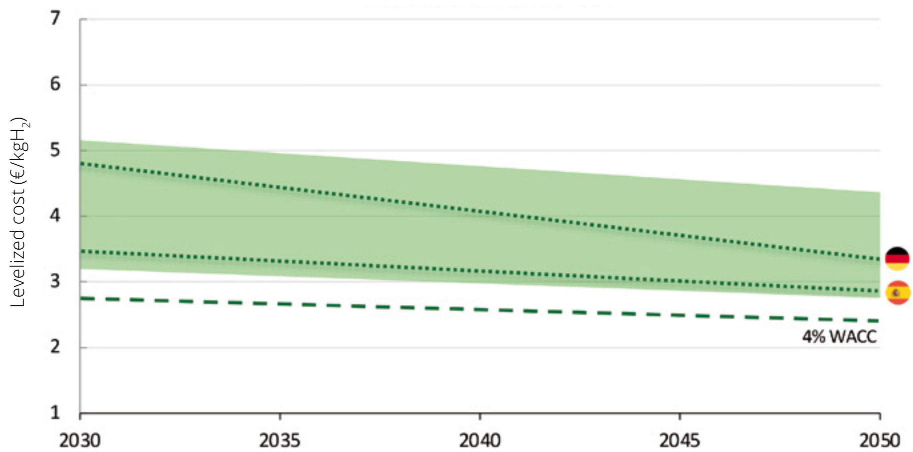
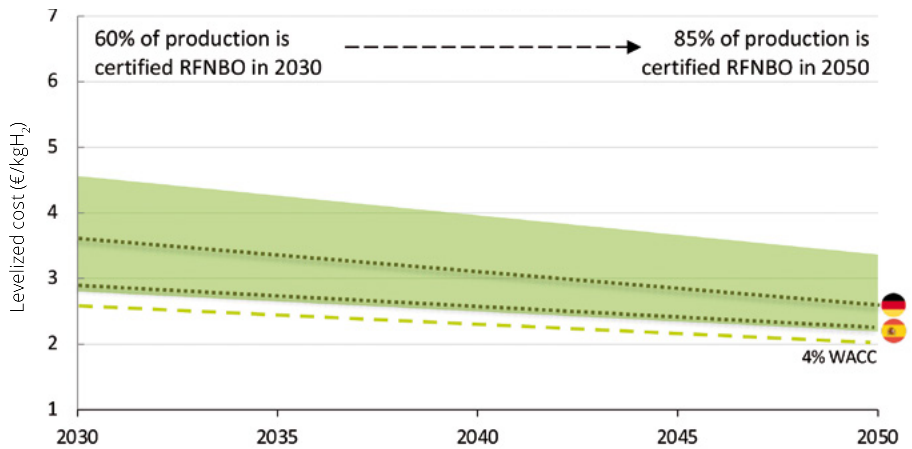


Figure 23. Evolution of LCOH over time for grid-based LCH production



Countries with large wind and solar endowments tend to have the lowest production costs for electrolytic hydrogen production. The LCOH of RFNBO using dedicated renewable energy sources is primarily driven by the cost of renewable electricity production, which depends on the location and available resources. Similarly, countries with lower renewable potential will have a higher reliance on non-variable sources, with higher marginal costs leading to higher electricity prices. Within the EU, the LCOH varies widely among member states, reflecting the heterogeneity in their renewable energy resources, current installed production units and market conditions. Countries like Spain and Portugal, with abundant solar resources, or Denmark with prolific wind resources, have some of the lowest LCOH in the EU. In those countries – and especially in Southern Europe – electrolytic hydrogen is more competitive than fossil gas-based production. Conversely, Belgium and Germany have among the highest LCOH because of relatively lower renewable energy potential and higher electricity prices which gives the competitive advantage to fossil gas-based LCH and LCH imports. This disparity underscores the importance of regional cooperation in balancing the differences and reducing the overall supply costs of hydrogen within the region.

Whilst LCOH for fossil gas-based hydrogen production is highly sensitive to natural gas market prices, it is in the near term among the most cost-competitive options in a large part of Europe. Yet, the competitive advantage of fossil gas-based production over electrolytic options fades over time. As such, countries with access to the CO_2 transport network would likely favour fossil gas-based supply. This poses the risk of a "lock-in" effect if early investments in reformers or gas supply delay the transition to cheaper and more sustainable alternatives later. However, this is somewhat mitigated by the binding targets for RFNBO usage laid out in RED III that prevent fossil gas-based hydrogen from capturing a dominant share in each national market.

Figure 24. Evolution of LCOH over time for fossil gas-based LCH production

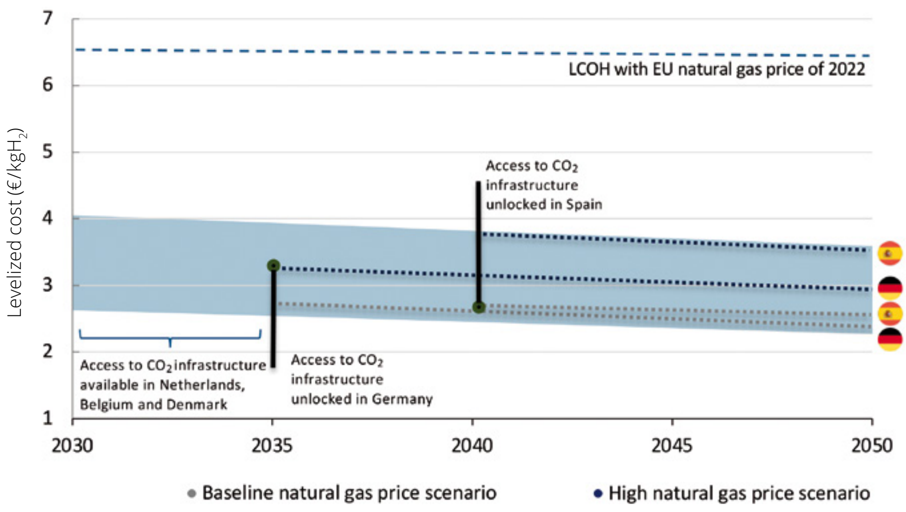
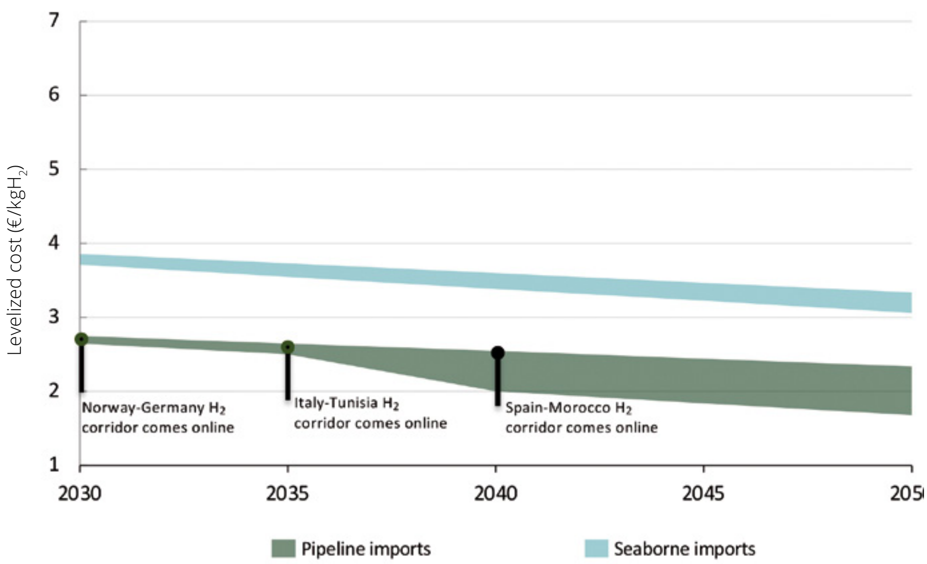


Figure 25. Evolution of LCOH over time for LCH imports

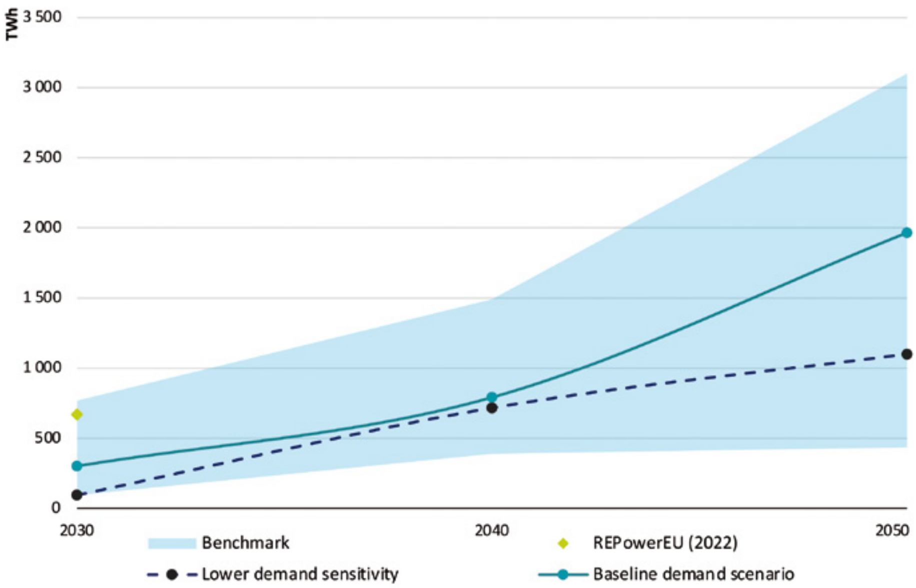


Note: Values are calculated with a 6% WACC unless otherwise indicated. The baseline natural gas price trajectory assumes €30/MWh in 2030, €25/MWh in 2040, and €22/MWh in 2050 (see appendix A4). The high natural gas price trajectory assumes a price trajectory of €45/MWh in 2030, €40/MWh in 2040, and €35/MWh in 2050. In 2022, the EU natural gas price corresponds to the yearly average value of €111/MWh. For further assumptions on ETS price trajectory, CAPEX, OPEX, among other, refer to the appendix A4.

A baseline and a low demand trajectory are considered to grasp the uncertainties around the take-off of the European hydrogen industry and assess impact of regulation upon them as presented in Figure 26. The baseline trajectory is based on the long-term figures of the European Commission 2040 Impact Assessment[37]. Since the EC does not provide any official 2030 figure, a literature review and an assessment of different national and European targets was conducted leading to likely baseline demand of 300 TWh in 2030.

The LCOH curves are relatively flat in each country. Installing additional reformers or renewables should not necessarily be much more expensive than the previous unit in the same country. Therefore, different demand levels have only little impact on cost competitiveness on the supply side. However, the demand level can impact the hydrogen and CO_2 transport infrastructure costs, which is not depicted in this study. This would impact the technology feasibility and the market structure. If the development of hydrogen or CO_2 pipelines is limited or delayed, mainly small co-located units could see the light leading to a distributed industrial landscape.

Figure 26. EU hydrogen demand trajectories considered (excluding derivatives imports)

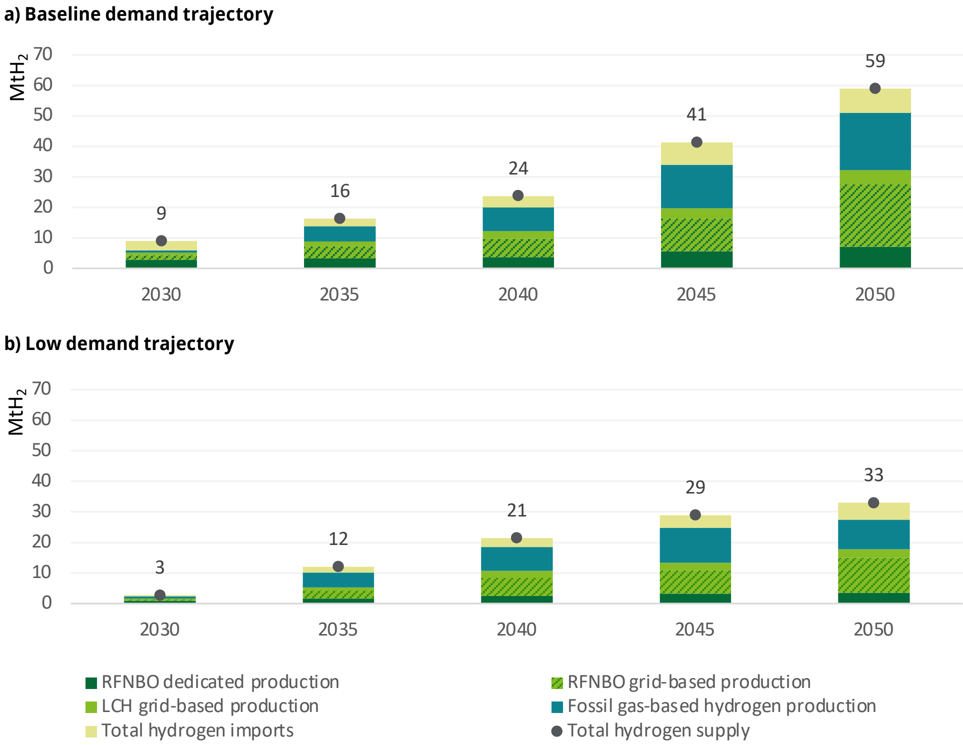


Note: further information about the benchmark is available in Appendix A4.

37 Impact Assessment Report of 6 February 2024 accompanying the document "Securing our future – Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society"

As a result of renewable energy development in the power sector, the RFNBO grid-based production is the fastest-growing hydrogen supply source, as shown in Figure 27. Towards net-zero in 2050, a massive deployment of solar photovoltaic and wind in the EU electricity mix would not only drastically reduce the carbon intensity of power supply but would also mean that the power system would be dominated by renewables. This also implies a significant amount of hours over the year with very low prices, which in turn improves the cost competitiveness of grid-connected electrolysers. Therefore, as the power system transitions, grid-based LCH naturally sees its emissions fall, and becomes, to a large extent, RFNBO-compliant while also gradually improving its cost competitiveness over time.

Figure 27. Clean hydrogen supply mix with the 70% threshold assuming yearly average carbon intensities. a) baseline demand trajectory, b) low demand trajectory



Highly cost competitive in some regions, fossil gas-based technologies could supply nearly 20 MtH_2 by 2050 in the baseline demand scenario under current regulation. Mirroring the development of CO_2 transport infrastructure, EU fossil gas-based hydrogen share in the production mix grows from 8% of the total hydrogen supply in 2030 to 32% in 2050. However, this aggregated value hides vast discrepancies at the country level. In Southern Europe, high solar potential and the long distance to CO_2 storage sites in the North Sea foster the electrolytic hydrogen production. Conversely, lower renewable energy endowments and connections to offshore CO_2 storage sites make fossil gas-based LCH more competitive in Central Europe. As such, fossil gas-based production represents respectively 52% and 7% of supply in the Netherlands and in Spain over the 2030-2050 timeframe. Overall, gas consumption for hydrogen production corresponds to 2% of current European gas imports in 2030 and could go up to 27% in 2050 in a baseline hydrogen demand scenario. In a low demand scenario, natural gas consumption for LCH production would represent less than 1% of current gas imports in 2030 and 15% in 2050.

In the short-term, the EU could heavily rely on clean hydrogen imports mainly coming from Norway. As shown in Figure 27, the EU source up to 35% of its needs in 2030 from imports, totalling to approximately 3 MtH_2 out of the 9 MtH_2 of demand in the baseline hydrogen demand scenario. In a low-demand scenario, imports go down to 0.5 MtH_2 in 2030. About half of these imports come from Norway, where fossil gas-based and electrolytic hydrogen production costs are low. This result is a direct consequence of the current development stage of both pipeline connections with Europe and announced electrolytic and fossil gas-based projects[38].

Although imports grow in absolute terms the share of imports in the EU's total consumption decreases in the long term. In fact, only 14 % of the EU's total demand in 2050 will be served by imports (of which 5% come from Norway). The reduction of the EU's dependency on imports stems from an uptake in the increasingly cost-competitive domestic production as European power grids decarbonise and economies of scale prevail. In a scenario with lower hydrogen demand, import dependency also decreases in the short-term, falling to 18% of the hydrogen supply, as fewer volumes of seaborne imports are required (Table 3).

Apart from imports from non-EU countries, each member state's hydrogen supply is complemented by pipeline trade within the EU. Hydrogen flows from countries with lower production costs, such as Spain and Portugal in Southern Europe, to countries with higher production costs, including Belgium, the Netherlands, to some extent Germany, through France, which also acts as a net exporter. However, the extent of intra-European hydrogen trade is limited by the available pipeline capacity assumed[39]. Creating a European market that enables complementarities between regions with abundant and affordable hydrogen production capabilities and others where significant demand will be sitting would depend on the emergence of a hydrogen pipeline infrastructure.

Table 3. Key metrics with 70% threshold assuming yearly average carbon intensities, with a baseline hydrogen demand scenario as reference

	Baseline demand scenario	Low-demand scenario
Average LCOH	2030: 3.51 €/kgH_2 2050: 2.62 €/kgH_2	2030: 3.26 €/kgH_2 2050: 2.39 €/kgH_2
Share of fossil gas-based LCH	2030: 8% 2050: 30%	2030: 22% 2050: 29%
Share of imports	2030: 35% 2050: 14%	2030: 18% 2050: 17%

38 Norwegian exports projects – especially towards Germany – are developed in the German-Norwegian Energy Cooperation Joint Feasibility Study from GASSCO and DENA

39 Based on ENTSOG TYNDP 2022 (ENTSO-G 2022) and the EU Hydrogen Backbone studies from Guidehouse (2022b)

3.3 A dynamic emissions threshold aligned with the net-zero target

RED III uses a 94 gCO_2eq/MJ fossil fuel comparator and defines the threshold to lead to at least 70% GHG emission reductions. Set in this way, the threshold requires hydrogen to be produced at below 3.38 $kgCO_2eq/kgH_2$. This standard aims to foster consistency and comparability across different clean alternative fuels and products thereby promoting uniformity in evaluating and achieving GHG emissions reductions. For consistency, the same threshold is to be used in the upcoming Delegated Act on Low-Carbon Fuels. Several calls have been made to reduce the level of this threshold, which is significantly higher than that of the United Kingdom's Low Carbon Hydrogen Standard (2.4 $kgCO_2eq/kgH_2$).

The calculated comparator and reduction threshold should be periodically updated to reflect changes in technology, fuel composition, or industry practices to ensure that these values offer significant reductions in GHG emissions. As such, the Hydrogen and Decarbonised Gas Market Directive integrates the possibility of reviewing this threshold for production assets coming online after 2030. Ultimately, the reduction of threshold and fossil fuel comparator should align with the EU's climate goals and the objective of reaching carbon neutrality by 2050.

A decreasing threshold would allow regulatory incentives to evolve in lockstep with the fast decarbonisation of the power sector and would ensure LCH delivers CO_2 savings on the path to net-zero. The current static level requires the CO_2 intensity of grid electricity to be around 60 CO_2eq/kWh (depending on the efficiency of the electrolyser). The fast development of renewables and low-carbon technologies in the electricity mix will make the EU27 cross this threshold by 2030 (on average), as shown in Figure 7. This means the current static threshold would become irrelevant within the next decade for grid-based LCH production if the yearly average accounting methodology were selected.

By 2050, emissions, even if marginal, would only add a burden to the system. A decreasing threshold compatible with the net-zero targets should at least align with the expected global average of an authoritative net-zero scenario. Using the IEA's net-zero scenario, an EU threshold compatible with the climate target would lead to 1 $kgCO_2eq/kgH_2$ in 2050. Figure 28 shows that this value represents about a third of the current EU threshold of 3.38 $kgCO_2eq/kgH_2$. Obviously, many trajectories can be proposed to connect these two values; a linearly decreasing evolution of thresholds is a simple and straightforward way to provide visibility to industrial stakeholders in planning investment decisions.

Figure 28. Setting thresholds compatible with a net-zero goal

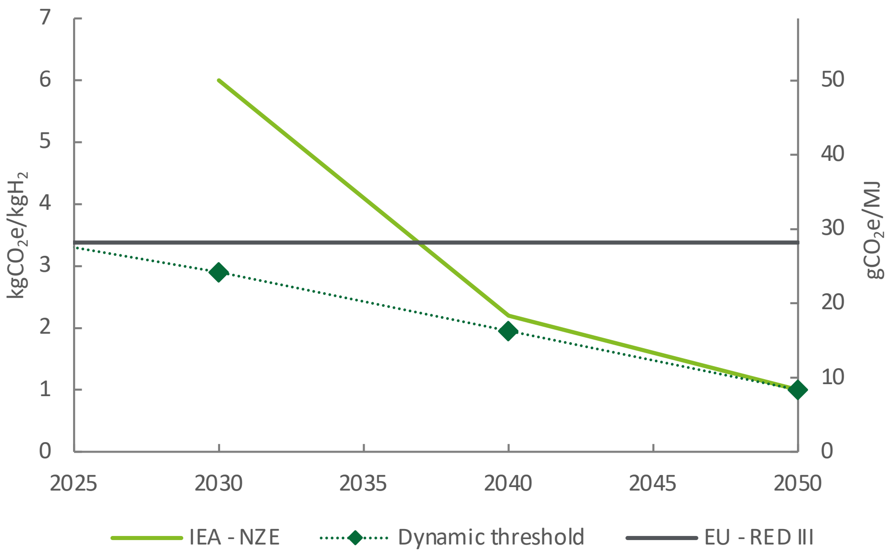
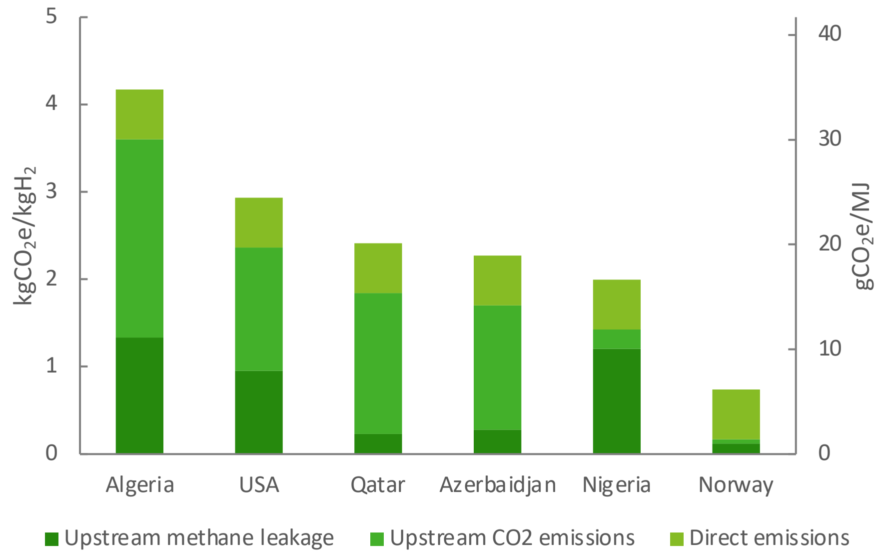


Figure 29. Hydrogen GHG footprint from ATR with 95% capture rate with current upstream emissions factors



A decreasing threshold would be an instrument to incentivise fossil gas-based LCH producers to procure natural gas from suppliers with a strong commitment to continuously reduce upstream emissions. Abating upstream emissions of natural gas production requires measures and investments throughout the value chain. As shown in Figure 29 upstream methane emissions from natural gas suppliers are heterogeneous, as are the CO_2 emissions associated with production, processing, and transport. Suppliers with significant upstream emissions, such as Algeria, Nigeria, and the US, must deploy short-, mid-, and long-term measures to catch up with best-in-class producers like Norway. By relying on a static threshold, the fossil gas-based LCH producers could procure their natural gas from suppliers that focus on the implementation of short-term measures to marginally undercut the threshold. Therefore, a decreasing threshold is a precondition for fair market competition between gas suppliers that are front-runners in methane emission abatement and laggards.

For assessing the impact of a decreasing threshold towards 2050 and the uncertainties on the adoption of BAT for reducing natural gas upstream emissions three cases are compared. Keeping the hydrogen demand constant, we compare the development of the hydrogen industry under a static threshold, as a reference, against a linearly decreasing threshold converging towards 1 $kgCO_2eq/kgH_2$ in 2050 with and without the adoption of BAT. With a baseline demand, static threshold and no BAT, the associated direct emissions of total electricity and hydrogen supply would represent around 60 $MtCO_2eq$ emissions in 2050.

With a decreasing threshold, the production and market shares of fossil gas-based LCH are driven by the extent to which gas suppliers can adopt BAT. If all suppliers adopt BAT, the resulting market shares of fossil gas-based LCH with a progressively decreasing threshold are very close to the case with a static threshold[40]. In this case, fossil gas-based LCH production could grow from about 1 MtH_2 in 2030 to 19 MtH_2 in 2050 (Figure 30).

This would lead to an emission reduction of about 230 $MtCO_2eq$ over the period (Table 4). However, the decisions and speed of adoption of BAT ultimately depend on the business strategies of natural gas suppliers. Although today, most supply countries show commitment and goodwill to timely uptake upstream abatement measures, there is a spectrum of possibilities to consider towards 2050 ranging from measures being limited, delayed or cancelled. In a case where no new abatement measures are adopted by suppliers, only natural gas coming from Norway to produce LCH would comply with a decreasing threshold. This would put the market shares of fossil gas-based LCH onto a low trajectory, peaking by the mid-2040s (Figure 30).

40 Assuming the adoption of BAT adoption has no price implication on EU natural gas prices

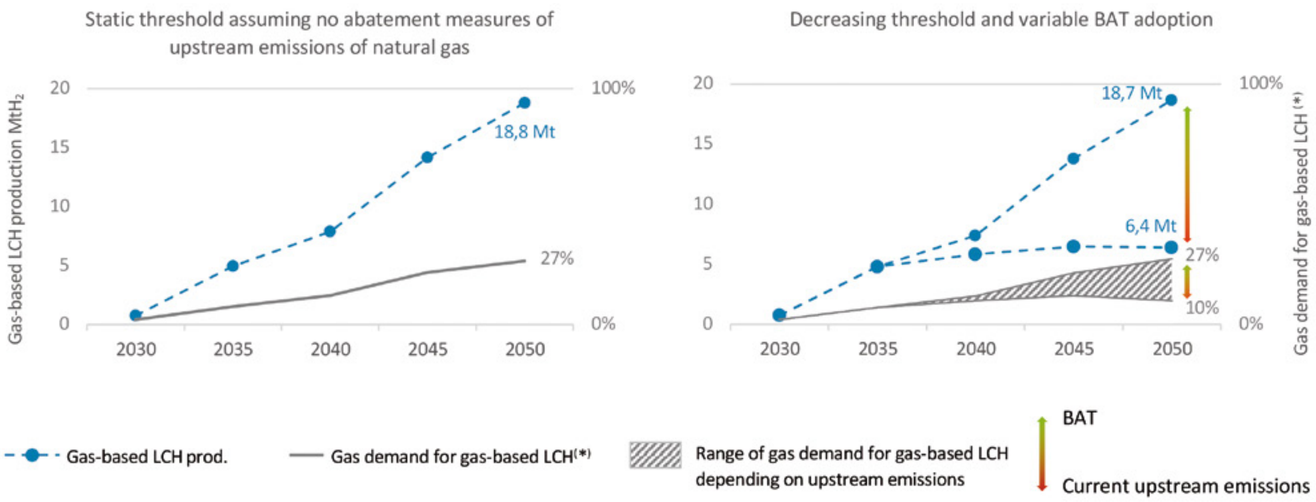
A decreasing threshold and the uncertainties on suppliers adopting BAT could lead to an increase in import volumes or an increase in supply concentration. The shares of natural gas required to produce LCH could go from about 6 bcm in 2030 to between 30-80 bcm in 2050 (Figure 30). This is about 2%, and 10-27% of the total EU27 gas demand of 2023, respectively. Even if it remains limited in 2030, this natural gas consumption would come off the top of current natural gas uses in Europe and would counter the expected descending trend of the REPowerEU plan.

Towards 2050, if all suppliers adopt BAT the additional 80 bcm alone would eat out about 43% of the REPowerEU target for 2030[41]. Conversely, if no supplier adopts BAT the 30 bcm required for LCH would need to flow from Norway, the only supplier eligible, which would represent about 35% of the total Norwegian gas exports to the EU in 2022.

Table 4. GHG savings with static and decreasing thresholds, and with and without BAT adoption

	Reference scenario Level of emissions threshold: Baseline (3.38 $kgCO_2eq/kgH_2$)	**No adoption of BAT Level of emissions threshold: Linear decrease to 1.0 $kgCO_2eq/kgH_2$**	**Adoption of BAT Level of emissions threshold: Linear decrease to 1.0 $kgCO_2eq/kgH_2$**
2030	–	-0.8 $MtCO_2eq$	-1.3 $MtCO_2eq$
2040	–	-4 $MtCO_2eq$	-7 $MtCO_2eq$
2050	–	-30 $MtCO_2eq$	-27 $MtCO_2eq$
Cumulative (2030-2050)	–	-193 $MtCO2_2eq$	**-230 $MtCO_2eq$**

Figure 30. Fossil gas-based LCH supply and associated natural gas demand by threshold design and distinguishing the impact of adoption of BAT

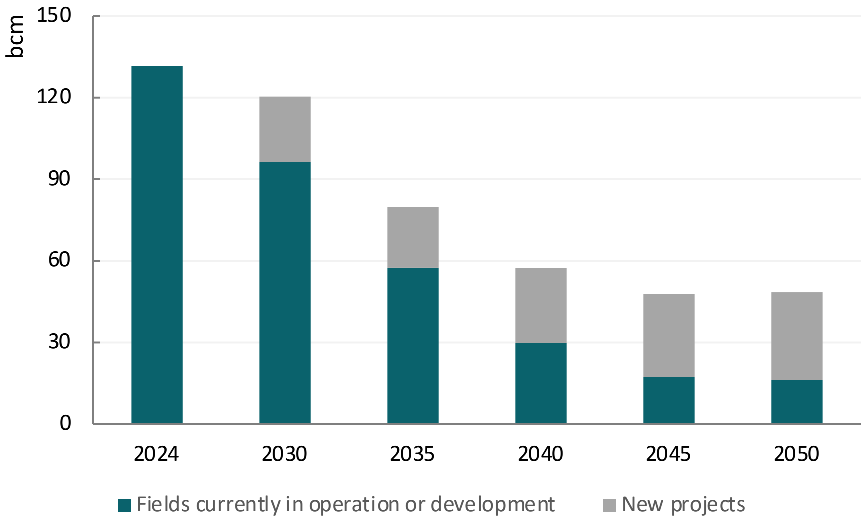


(*) As a share of 2023 gas consumption in Europe

41 Assuming it remains fixed over the period

The question of future Norwegian gas production remains open. Analysts foresee Norwegian gas production peaking by 2025 with a fast decline without the production of resources in new fields and discoveries, or slowly by including them[42] which indicates the "final phase of Norwegian petroleum activities" is to start (Figure 31). Moreover, the compatibility of new oil and gas exploration activities with the country's net-zero ambitions is currently being challenged at the highest level (The 2050 Climate Change Committee 2023)[43].

Figure 31. Projected natural gas production in Norway



Source: Based on data from Rystad Energy, values are retrieved from (Zero Carbon Analytics 2024)

42 Insights based on the Norwegian Offshore Directorate's production forecasts

43 The official report submitted by the 2050 Climate Change Committee to the Ministry of Climate and Environment recommends developing an oil and gas strategy permanently halting exploration activities without a direct connection to existing infrastructure as a natural step on the road towards the cessation of all further exploration. Further information is available at: The transition to low emissions, Climate policy choices towards 2050

Conclusions

Developing the low-carbon fuels regulation and certification scheme will require delicate trade-offs between multiple – and often contradictory – objectives. The upcoming regulation will have implications on (i) EU hydrogen and power GHG emissions, (ii) EU industrial competitiveness – through access to low-cost hydrogen supply, (iii) EU dependency on hydrogen and natural gas imports and (iv) on the take-off of the EU hydrogen industry.

In these trade-offs, **environmental integrity must remain at the forefront,** ensuring that the hydrogen produced is genuinely low-carbon and aligns with the European Climate Law. **Towards 2050, decreasing thresholds is the only way to rule out any production based on fossil gas with still significant upstream emissions and from electricity grids with residual emissions.** Thanks to a progressively more stringent threshold, up to 230 $MtCO_2eq$ emissions would be saved until 2050.

Similarly, **enforcing an hourly-granular grid emission accounting framework, at least for producers with significant capacities, yields environmental benefits at little extra cost.** It would enforce the operation of electrolysers according to the carbon intensity of the grid, improving system flexibility and creating market opportunities that would otherwise have been blocked with an accounting method based on annual averages.

The market competitiveness of each of the four supply routes analysed in this study – production from dedicated renewables (e.g. through a PPA), grid-based production, fossil gas-based production, and hydrogen imports – depends on the renewable energy potential, the legacy electricity mix and the access to natural gas supply and CO_2 infrastructure in each member state. Sweden and France[44], can today produce LCH with grid-connected electrolysers due to their legacy electricity mixes with very low-carbon intensity. Countries with very good renewable energy potential such as Spain, Portugal, Denmark and Austria, whose electricity mixes are to become renewable to a large extent, are set to produce electrolytic LCH and RFNBO in the short-term at very competitive costs. Italy, Greece and Germany could follow. The technological competitiveness and feasibility of producing low-carbon hydrogen in other member states would be determined by the interplays of their nuclear, natural gas and CO_2 infrastructure development strategies and the pace at which they can bring renewables to their power system. Thus, the different supply routes analysed are complementary at the EU level and their split **will not only be determined by cost competition but will be heavily influenced by regulatory targets, technological progress, infrastructure availability and risk perception.**

Grid-based hydrogen production rapidly grows and becomes the dominant production route in the EU mix, driven by the fast integration of renewables in national grids. Even if its initial development stage is uneven across member states due to differences in legacy mixes and largely influenced by grid emissions accounting methodology, over time, the EU interconnected electricity system gets predominantly powered by renewables. This, in turn, further improves the business case of flexible grid-based production. Hence, a greater share of grid-based production is RFNBO compliant.

44 Norway and Switzerland, although not being EU member states, are other European countries capable of producing grid-based LCH as of today.

Nevertheless, some uncertainties and technical challenges must be tackled to unleash the deployment of grid-based hydrogen production options. Firstly, clean power production should keep growing fast enough to supply new electrolysers in the context of rising power demand due to the direct electrification of end-uses.

Hydrogen production powered by dedicated renewable capacities is crucial in building the renewable hydrogen market but experiences only moderate growth. In the short-term, the EU demand for clean hydrogen is mainly driven by the RFNBO targets set in RED III, ReFuelEU Aviation Regulation and FuelEU Maritime Regulation. As the renewable shares in most national grids are still relatively low by 2030, a significant share of RNFBO production has to be based on "fully renewable electricity" under the rules of the Delegated Act on a methodology for renewable fuels of non-biological origin. However, in the longer term as grid-based production becomes increasingly RFNBO-compliant, the competitiveness of RFNBO through dedicated renewables – inherently less flexible – is reduced.

Even if fossil gas-based LCH production could be competitive in some parts of Europe with low renewable potential, its development is subject to large uncertainties. The modelling results suggest that fossil gas-based LCH could be pivotal in the EU hydrogen supply – especially in Central-West Europe but it also entails considerable risks such as:

- **Technological and CO_2 infrastructure development risk.** Compliance with the low-carbon threshold requires advanced carbon capture techniques that operational plants have not yet developed at scale (IEA, 2023). Technical and economic hurdles to deploying these techniques on large-scale projects could close the opportunity for fossil gas-based hydrogen producers. In parallel, fossil gas-based LCH projects hinge on the development of a CO_2 transport and storage infrastructure, which is currently at a very early stage (JRC, 2024). Uncertainties around the rollout of the CO_2 transport network, the permitting processes for storage capacities, and the design of the CCS regulatory frameworks are non-negligible.
- **Future gas price developments.** Natural gas feedstock is the main cost component of fossil gas-based LCH. Yet, natural gas prices have experienced extreme volatility recently, and project developers cannot be certain that they will have access to affordable gas supply for the entire lifetime of their projects. In particular, geopolitical tensions or supply chain disruptions could cause significant turmoil in natural gas markets and undermine the competitiveness of fossil gas-based hydrogen production.
- **Access to low-emissions natural gas.** Fossil gas-based LCH production would only be aligned with net-zero commitments if it relies on natural gas with minimal upstream emissions. With the current emission factors, only natural gas from Norway would qualify for LCH production after accounting for CCS. It remains uncertain whether other gas-exporting countries would be able – or willing – to adopt the advanced technologies required to reduce emissions in their gas value chain sufficiently. If these exporters do not adopt such measures, the EU may depend entirely on Norway for its hydrogen-related natural gas demand. In this case, it is unclear whether Norway could sustain the required level of gas supply in the long term.

The EU hydrogen imports have a two-fold impact, unlocking access to low-cost foreign production and bridging EU production shortcomings. Pipeline imports from neighbouring regions with large fossil gas resources or renewable endowments are highly competitive and constitute a cornerstone of EU hydrogen supply. Conversely, supply chain complexities raise significantly the costs of seaborne imports. Lesser competitive, seaborne imports are essentially used to bridge any production gap within the EU. The EU should monitor compliance with its environmental rules to avoid emissions moving outside of its borders.

To ensure security of supply, the EU should also lay out a coherent action plan for infrastructure deployment and supply risks mitigation. Establishing long-term partnerships with reliable and diverse suppliers is required to safeguard hydrogen supply from turmoils in world energy markets.

Laying out the EU low-carbon hydrogen regulation and certification scheme requires a balanced and deliberate approach. Designing the EU low-carbon fuel regulation is particularly complex. It needs to consider the specificities of each potential low-carbon production route and strike a careful balance that supports best-performing technologies, even if they might differ from one member state to another. It will have to navigate the diverse energy mixes of the member states, each with its legacy infrastructure, decarbonisation strategy and policy landscape. Furthermore, the upcoming delegated act will have to fit within an existing regulatory framework and be coherent with EU industrial, energy and environmental ambitions. Lastly, it should provide the necessary visibility to signal timely investments while remaining as future-proof as possible. An inappropriate regulatory framework could place a heavy burden on the EU industry and hydrogen economy or undermine environmental objectives. **The upcoming Delegated Act on Low-Carbon Fuels should come to emphasize the net-zero objectives and confirm the priorities to achieve it. It should be founded on the necessary balance between the short-term needs of the EU hydrogen industry in particular, and its geostrategic, economic and industrial ambitions in general.**

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Appendix

A1. Model architecture

The assessments of this study rely on quantitative modelling-based analyses conducted by Deloitte. The modelling framework represents the European interconnected power system and explores its transition until 2050, including the demand and supply of hydrogen at the country level. The modelling relies on Deloitte's European Electricity Market model (DEEM) and the HyPE model, an optimisation model that explores international hydrogen tradeflows.

To study the impact of EU regulations on the hydrogen economy, the analysis assumes exogenous demand trajectories in each EU27 country (see appendix A4). Various production routes are considered to meet this demand through global cost minimisation. Furthermore, the influence of regulations on total costs, total emissions, and the volumes of hydrogen produced and exchanged is examined.

The modelling architecture for this analysis includes representations of the possible evolution of both the electrical system in Europe until 2050 and the clean hydrogen economy. This outlook presents a vision for potential hydrogen development and trade flows, based on data-driven and model-based quantitative analysis.

A2. The DEEM Model

The DEEM (Deloitte European Electricity Model) is a mixed-integer linear programming model of the electricity market which optimises system operations and capacity expansion under a total system cost minimisation. It is the power system module of Deloitte's energy system model (DARE – Deloitte Applied Research on Energy Model). The model is composed of two linked modules. The first one, the power module models the equilibrium between the electrical demand and the production, it represents the day-ahead commitment of each power plant unit based on their marginal costs and technical constraints and the market price is deduced from the marginal value of the supply and demand constraint. The second one, the hydrogen module, models the equilibrium between hydrogen demand and hydrogen production. As one production route considered for hydrogen production is grid-based electrolysis, the hydrogen module is linked to the power module through the electrical load of the grid-connected electrolysers. This module allows the system to install and operate electrolysers, produce hydrogen from electrolysis, exchange hydrogen through pipelines and import hydrogen from outside Europe and produce hydrogen from natural gas thanks to the coupling with the HyPE model (see appendix A3).

From current installed capacities, the model simulates 2025 until 2050 with a 5-year in an iterative way and without perfect future foresee. Based on total electrical load (electrical load from grid-based hydrogen production, and all other electrical load), the model endogenously decides the commissioning or decommissioning of generation units. Regional specificities are taken into account (renewable endowment, commissioned projects and production patterns) as well as planned capacity (official nuclear commission and decommission plans, announced fossil phase-out and hydrogen-to-power capacities). Each country is represented by a node and countries are interconnected considering the interconnexion capacities of the European electricity grid.

$$C^{total} = \sum_{Countries} C^{Capital\ Cost} + C^{Production\ Cost}$$

Where $C^{Capital\ Cost}$ represents the annual capital expenditures of generation units and electrolysers, $C^{Production\ Cost}$ the operation cost which include operational expenditure and start-up cost. This equation is established for each year and minimised as the objective function. It encompasses all costs related to the power production and hydrogen production. The total production costs are the sum of all generation units and the cost occurring through the charging and discharging of storage facilities.

A set of constraint guarantees the coherence of the model and capture the specificities of each technology. Supply – demand equilibrium must be reached for both electricity and hydrogen, other constraints related to the power module can be found in (Cabot and Villavicencio 2024).

$$d_{z,y,h} + \sum_{z'} e_{z,y,h,z'} + \sum_{s} c_{z,y,h,s} = \sum_{k} G_{z,y,h,k} + \sum_{z'} i_{z,y,h,z'}$$

$$d^{H_2}_{z,y,h} + \sum_{z'} e^{H_2}_{z,y,h,z'} + C^{H_2}_{z,y,h} = \sum_{p} G^{H_2}_{z,y,h,p} + \sum_{z'} i^{H_2}_{z,y,h,z'} + Di^{H_2}_{z,y,h}$$

Where:

Element	Description	Unit
y	Year	
z, z'	Country	
h	Hour of the year	
k	Generation technology considered	
p	Hydrogen production route	
s	Storage technologies	
$d_{z,y,h}$	Hourly electricity demand of the considered country	[MWh]
$e_{z,y,h,z'}$	Power export between two countries	[MWh]
$c_{z,y,h,s}$	Hourly charging of storage technologies	[MWh]
$G_{z,y,h,k}$	Hourly production of a given technology k in a country z	[MWh]
$i_{z,y,h,z'}$	Power import between two countries	[MWh]
$d^{H_2}_{z,y,h}$	Hourly hydrogen demand in the considered country	[MWh_H_2]
$e^{H_2}_{z,y,h,z'}$	Hourly hydrogen export via pipelines	[MWh_H_2]
$C^{H_2}_{z,y,h}$	Hourly hydrogen storage charge	[MWh_H_2]
$G^{H_2}_{z,y,h,p}$	Hourly hydrogen supply via production route p	[MWh_H_2]
$i^{H_2}_{z,y,h,z'}$	Hourly hydrogen import via pipelines	[MWh_H_2]
$Di^{H_2}_{z,y,h}$	Hourly hydrogen storage discharge	[MWh_H_2]

Each country has a hydrogen demand to meet on an hourly basis. This demand can be met though domestic production (gas-based or electrolysis), exchange via hydrogen pipelines, import from countries outside of Europe and use of hydrogen underground storage. All these routes to meet the demand are in competition to minimise the system costs. For domestic productions, three options are available: gas-based production, grid-based electrolytic hydrogen, and off-grid electrolytic hydrogen. All production methods must comply with the GHG reduction threshold. For grid-based electrolytic hydrogen, this means that electricity from the grid can only be used when its carbon emission content is sufficiently low. Electricity supplied to the electrolysers through PPA is modelled as "off-grid production," despite usually being connected to the grid. This representation ensures compliance with the criteria outlined in Delegated Act 2023/1184. In particular, temporal correlation, geographical correlation and additionality are ensured through a set of equations similarly as in (Villavicencio, Brauer, and Trüby 2022).

Hydrogen production through electrolysis follows the following equation, with $Lgrid_{z,y,h}^{H_2}$ the hourly electrical load of the grid (MWh), $Lres_{z,y,h}^{H_2}$ the hourly electrical load of electricity from dedicated off-grid renewable (MWh), $\eta_{y,electrolyzer}$ the efficiency of the considered electrolyser (MWh_H_2/MWh).

$$G_{z,y,h,electrolysis}^{H_2} = \sum_{electrolyzer} \left(Lgrid_{z,y,h}^{H_2} + Lres_{z,y,h}^{H_2}\right) * \eta_{y,electrolyzer}$$

The electricity supplied to the electrolyser is limited by the system's installed capacity, similar to how power generation is constrained by the installed capacity and availability of each generation unit.

The model relies on several assumptions presented in A4 concerning capital costs, operational costs, commodities prices and infrastructure.

A3. HyPE Model

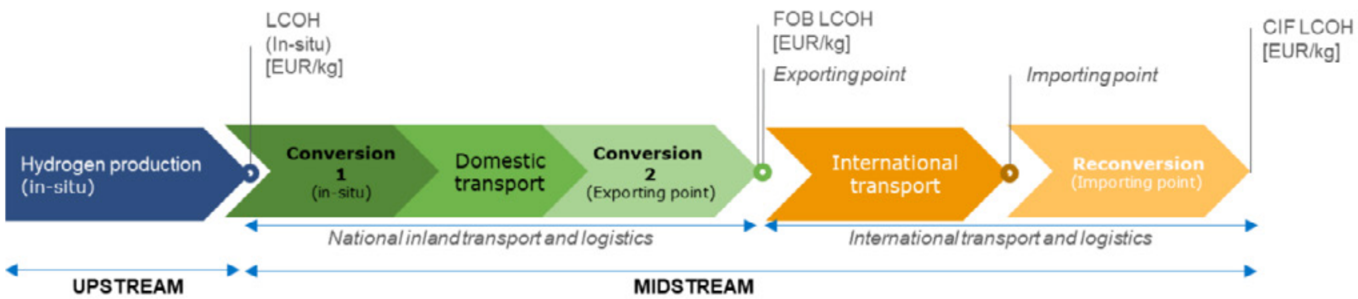
HyPE model is an optimisation model representing the value chain for clean hydrogen and its derivative. The optimisation finds the least cost solution to supply hydrogen to European countries considering trade routes and production potential. The model represents the value chain for hydrogen production until consumption, modelling both the upstream (hydrogen production) and midstream sector (conversion, transport and reconversion). The detailed methodology of the model and main equations can be found in (Deloitte 2023).

Hydrogen volumes and prices are derived based on a merit order logic of the LCOH metric. Hydrogen demand hubs are considered to derive the import supply curves to Europe. The model also computes the gas-based production potential in European countries. The model provides DEEM hydrogen import potentials and gas-based domestic production potential to represent competition between domestically produced hydrogen and imports.

Hydrogen production costs and volumes are derived from off-grid renewable energy and from methane with abated CO_2 emissions. For off-grid renewable energy, they are derived based on land availability (land available excluding water bodies, forests, natural parks, used lands and cities), maximum wind turbines and solar panels deployment, deployment rates and power density of solar and wind power technologies. Gas-based hydrogen potential is assessed through domestic consumption trajectories, commercial balance and available resources.

The assessment includes several transport options, such as hydrogen trucks and domestic hydrogen gas pipelines for national transport. For international transport, tankers and pipelines serve as the main hydrogen transport options. At the export site, hydrogen derivatives (ammonia, methanol, and SAF) facilitate export purposes, and conversion is assumed to occur only at the consumption location for domestic use.

The model provides DEEM with supply curves. This allows a comprehensive representation of the competition between the different hydrogen supply routes. Prices and volumes associated with LCH hydrogen imports from outside of Europe and domestic gas-based production are incorporated as available import options to satisfy European demand in DEEM.



A4. Baseline assumptions and input data

Hydrogen demand

This study focuses on EU hydrogen supply, and therefore does not include an assessment of potential EU demand trajectories. Given the large uncertainty over the realisation of EU clean hydrogen demand toward 2050, two different demand trajectories have used to ensure the robustness of the supply assessments. The demand trajectories included in the modelling are exogenous and derived from the economic literature. They have been revised to include only EU demand for pure hydrogen molecules, imports of derivatives are excluded as the economic trade-off is then different than for hydrogen imports or local production (Deloitte, 2023). The "baseline trajectory" is extracted from (European Commission, 2024) with a 2030 value manually set at 300 TWh[45].

To ensure the relevance of the two selected trajectories, they have been compared to a benchmark of demand trajectories used in the literature (Figure 26). This benchmark is based on the scenarios collection performed by the European Hydrogen Observatory which lists "some of the most recent and widely recognised studies proposing one or more hydrogen demand scenarios for 2030, 2040 and 2050 by sector" (European Hydrogen Observatory, 2023).

Hydrogen transport infrastructure

Hydrogen transmission capacities are based on ENTSOG TYNDP 2022 (ENTSO-G 2022) and commission dates are corrected based on (Guidehouse 2022b) and the probability of the interconnector being available. The assumed hydrogen pipelines capacities and start of operation are listed in Table 5.

Hydrogen exchange through pipelines are associated a unit cost per kg of hydrogen transported which is a function of the pipelines length and share of repurposed infrastructure used in the interconnection. Those costs are assumed to be constant over time and are set at 0.32€/kgH_2/1000km for new pipelines and 0.11€/kgH_2/1000km for repurposed ones based on (International Energy Agency 2023a) and (European Hydrogen Backbone 2022).

Table 5. Assumptions on pipeline capacities and commission date

Interconnected countries		Transmission capacity (GWh/d)	Commission Date
Algeria	Italy	448	2035
Austria	Germany	150	2035
Austria	Italy	Austria - Italia : 126 Italia - Austria : 168	2035
Austria	Slovakia	144	2030
Austria	Slovenia	Austria - Slovenia : 33 Slovenia - Austria : 16	2040
Belgium	France	108	2030
Belgium	Germany	91	2030
Belgium	Netherlands	Belgium - Netherlands : 48 Netherlands - Belgium : 72	2030
Bulgaria	Greece	Bulgaria - Greece : 80 Greece - Bulgaria : 76	2030
Bulgaria	Romania	Bulgaria - Romania : 18 Romania - Bulgaria : 111	2030
Croatia	Hungary	128	2040
Croatia	Slovenia	Hungaria - Slovenia : 16 Slovenia - Hungaria : 33	2040
Czechia	Germany	144	2035
Denmark	Germany	290	2030
Estonia	Finland	Estonia - Finland : 100 Finland - Estonia : 200	2030
Estonia	Latvia	Estonia - Latvia : 200 Latvia - Estonia : 100	2030
Finland	Germany	504	2030
Finland	Sweden	666	2030
France	Germany	France - Germany : 204 Germany - France : 192	2030
France	Spain	216	2035
Germany	Netherlands	Germany - Netherlands : 12 Netherlands - Germany : 375	2030
Germany	Poland	Germany - Poland : 100 Poland - Germany : 200	2035
Hungary	Romania	154	2030
Hungary	Slovakia	200	2030
Hungary	Slovenia	20	2040
Italy	Slovenia	20	2040
Italy	Switzerland	Italy - Switzerland : 88 Switzerland - Italia : 135	2030
Latvia	Lithuania	200	2030
Lithuania	Latvia	100	2030
Lithuania	Poland	Lithuania - Poland : 200 Poland - Lithuania : 200	2030
Norway	Germany	414	2030
Portugal	Spain	81	2040
Slovakia	Czechia	144	2030
Spain	Italy	320	2040

45 Based on an analysis of the national and EU regulatory targets and hydrogen strategies

CO_2 transport and storage infrastructure

This study assumes that CO_2 captured in EU can only be stored in offshore sites in the North Sea in accordance with the B2 scenario of (JRC, 2024). CO_2 storage costs are set at 10.2€/tCO_2 based on (Roussanaly et al 2021).

As CO_2 transport by ships or trucks is unlikely to be economical (Global CCS Institute, 2021), the modelling in this study assumes that fossil gas-based hydrogen can only be produced in countries connected to a CO_2 transport pipeline network linking production sites with the offshore CO_2 storage sites in the North Sea. A gradual expansion of this CO_2 pipelines network has been modelled. By 2030, it is assumed that only Norway, Denmark and the Netherlands have a pipeline access to the storage sites and are therefore potential fossil gas-based hydrogen producers. By 2035, the network is expanded to neighbouring large economies (Germany, Belgium and France) while the rest of Europe completes its connection to CO_2 network by 2040.

CO_2 transport costs are uneven across countries as they depend on distance to the storage sites. Unitary CO_2 transport costs are based on (Roussanaly et al 2021) and set at 41€/tCO_2/1000km for onshore transport and 37€/tCO_2/1000km for offshore transport.

Techno-economic assumptions

Tables 6 to 10 list the key techno-economic assumptions which are underpinning the endogenous model investment and operation decisions in power and hydrogen production assets.

Table 6. Evolution of capital cost of main technology considered (in 2023€/kW)

Technology	Lifetime	2025	2030	2040	2050
Solar panels	20	970	670	550	430
Onshore wind	20	1420	1190	1150	1100
Offshore wind	20	3450	2400	2210	1820
Thermal Power plant CCGT	25	1142	/	/	/
Natural gas CCGT with CCS	25	1752	/	/	/
Alkaline electrolyser	20	1 290	834	783	639
PEM electrolyser	20	1148	993	890	707
SOEC electrolyser	20	2307	1375	1153	887
SMR-90%[46]	25	1 333	1 171	1 109	1 047
ATR-95%[48]	25		1 074	925	814

Source: Analysis based on (IEA Greenhouse gas R&D Programme 2019; Department for Energy Security an Net Zero 2021; IEA 2023a; Danish Energy Agency 2024; Clean Hydrogen Joint Undertaking 2022; DNV 2022; IEAGHG 2022)

Table 7. Evolution of O&M cost technology considered (in 2023€/kW/y)

Technology	2025	2030	2040	2050
Solar panels	16	11	9	8
Onshore wind	28	27	26	26
Offshore wind	102	741	65	60
Thermal Power plant CCGT	42	/	/	/
Natural gas CCGT with CCS	67	/	/	/
Alkaline electrolyser	48	37	34	29
PEM electrolyser	39	33	29	27
SOEC electrolyser	277	165	138	106
SMR-90%	42	40	40	39
ATR-95%	40	40	40	40

Source: Analysis based on n (IEA Greenhouse gas R&D Programme 2019; Department for Energy Security an Net Zero 2021; IEA 2023a; Danish Energy Agency 2024; Clean Hydrogen Joint Undertaking 2022; DNV 2022; IEAGHG 2022)

46 Steam Methane Reformers with 90% capture rate

47 AutoThermal Reformers with 95% capture rate

Table 8. Baseline price trajectories of key commodities

Technology	Unit	2025	2030	2040	2050
Natural gas	2023€/MWh$_{LHV}$	42	33	25	22
Coal	2023€/MWh	15	13	11	9
EU ETS	2023€/tCO_2	84	132	179	210

Source: KNDE2 Benchmark with TTF - Futures (12/04/2024), (IEA 2023b; International Energy Agency 2023b; UBA 2023; BMWK 2022; TYNDP 2022; Wood Mackenzie 2024)

Table 9. Electrolysers power consumption (kWhe/kgH_2)

Technology	2025	2030	2040	2050
Alkaline electrolyser	55	54	51	48
PEM electrolyser	54	51	48	45
SOEC electrolyser	41	41	41	40

Source: Based on (DNV 2022; Danish Energy Agency 2024; Department for Energy Security an Net Zero 2021; IRENA 2021; Holst et al. 2021; Clean Hydrogen Joint Undertaking 2022; IEA 2023a)

Table 10. Reformers technical characteristics

Technology	Direct emissions (kgCO_2eq/ kgH_2)	Natural gas consumption (kWh/kgH_2)	Power consumption (kWhe/kgH_2)
SMR-90%	1.0	48.0	1.0
ATR-95%	0.57	40.9	2.2

Source: Analysis based on (International Energy Agency 2023c; IEAGHG 2022)

Investments and phase-out decisions in nuclear and coal power production assets relate more to political choices than techno-economic optimisations. As such, the national evolutions of coal and nuclear capacities are defined exogenously based on the latest public announcements. Coal and nuclear modelling choices are respectively summarised in Table 11 and Table 12.

Table 11 Announced coal phase-out

Country	Coal phase-out
Germany	2038
France	2030
Spain	2030
Italy	2025
UK	2024
Portugal	2021
Netherlands	2029
Ireland	2025
Belgium	2021
Sweden	2021
Norway	2021
Finland	2029
Poland	2049
Czechia	2033
Bulgaria	2049
Austria	2021
Greece	2025
Denmark	2028
Hungary	2025
Luxembourg	2021

Source: based on (Our World In Data 2024)

Table 12. Nuclear installed capacity based on commissioning and decommissioning lines announced (in MWe)

Country	2025	2030	2035	2040	2045	2050
France	57 235	57 235	57 235	60 195	43 790	25 240
Belgium	2 077	2 077	2 077	0	0	0
Czech Republic	4 212	4 212	4 212	5 412	7 302	7 482
Finland	4 369	4 369	4 369	2 972	2 972	2972
Netherlands	482	482	2 000	2 000	2 000	2 000
Poland	0	0	3 750	6 150	8 550	9 750
Sweden	6 944	6 944	9 444	7 323	2 500	2 500
United-Kingdom	5 883	9 323	9 323	9 323	10 236	8 996
Spain	7 116	7 116	0	0	0	0

Source: based on (World Nuclear Association 2024), accessed 14/05/2023. Additional hypothesis: lifetime of nuclear reactor of 60 years, 10-year construction period before commissioning.

A5. Levelized cost of hydrogen calculation

In the study, four different routes are analysed, each employing a distinct calculation method to determine the levelized cost of hydrogen production. For all routes, the levelized cost of hydrogen is calculated by dividing the total cost associated with hydrogen generation by the amount of hydrogen produced (in kg).

RFNBO via off-grid dedicated renewable or PPA

This production route involves costs linked to installing and operating electrolysers and dedicated generation units. The levelized cost of hydrogen produced from electrolysers fed by off-grid dedicated renewables or PPA in the country z is defined by:

$$LCOH_{dedicatedRES,z} = \frac{CAPEX_{H2,z} + CAPEX_{RES,z} + \sum_Y \frac{OPEX_{H2,z} + OPEX_{RES,z}}{(1+WACC)^Y}}{\sum_Y \frac{P^{H_2}_{z,y,dedicatedRES}}{(1+WACC)^Y}}$$

Where $CAPEX_{H2,z}$ is the capital expenditure of the electrolyser, $CAPEX_{RES,z}$ is the capital expenditure of the renewable energy sources installed to produce electricity used by the electrolysers, $OPEX_{H2,z}$ the operation cost of the electrolysers, $OPEX_{RES,z}$ the operation cost of the renewable energy sources, $P^{H_2}_{z,y,dedicatedRES}$ the hydrogen produced from the "dedicated renewable energy sources" route and WACC the weighted average cost of capital.

Grid-based LCH

Contrary to the "dedicated RES route", there are no costs associated with the installation and operation of dedicated generation units. Instead, the additional cost arises from electricity consumed from the power grid, which is proportional to the market price.

The levelized cost of hydrogen produced from electrolyser sourcing electricity from the grid is:

$$LCOH_{grid-based,z} = \frac{CAPEX_{H2,z} + \sum_Y \frac{\left(OPEX_{H2,z} + \sum_h M_{z,y,h} * Lgrid^{H_2}_{z,y,h}\right)}{(1+WACC)^Y}}{\sum_Y \frac{P^{H_2}_{z,y,grid-based}}{(1+WACC)^Y}}$$

Where $M_{z,y,h}$ is the market price of the country in the considered hour, $Lgrid^{H_2}_{z,y,h}$ is the load of the electrolyser to the power grid and $P^{H_2}_{z,y,grid-based}$ the hydrogen produced from the "grid-based" route.

Gas-based LCH

The cost associated to the gas-based route includes the costs of the reformers, the cost of the gas consumed, the cost of the electricity consumed for the CO_2 capture and the carbon price of unabated carbon emissions. The levelized cost of hydrogen is given by:

$$LCOH_{gas-based,z} = \frac{CAPEX_{ref.,z} + \sum_Y \frac{\left(OPEX_{ref.s,z} + C_{EU-ETS} * e_z^{CO2} + \sum_h d_{gas,z,y,h} * P_{gas,y,h} + M_{z,y,h} * Lref.^{CO2}_{z,y,h}\right)}{(1+WACC)^Y}}{\sum_Y \frac{p^{H_2}_{z,y,gas-based}}{(1+WACC)^Y}}$$

Where $CAPEX_{ref.,z}$ is the capital expenditure of the reformers, $OPEX_{ref.s,z}$ the operation cost of the reformers, $d_{gas,z,y,h}$ the gas demand, $P_{gas,y,h}$ the gas price, $Lref.^{CO2}_{z,y,h}$ the electrical load for the CO_2 capture and $p^{H_2}_{z,y,gas-based}$ the hydrogen produced from natural gas reforming.

LCH Imports

Hydrogen supplied through the imports are produced either from dedicated renewable sources electrolytic production or from gas-based production. However, there are additional costs linked to the midstream part of the value chain, in particular transport and conversion/reconversion of hydrogen. The levelized cost of hydrogen production is thus equal to:

$$LCOH_{impot,z} = LCOH_{gas-based\ or\ dedicatedRES,z} + C_{transport,z,y} + C_{conversion,z,y} + C_{reconversion,z,y}$$

Where $C_{transport,z,y}$ is the cost of transport, $C_{conversion,z,y}$ the cost of conversion of the hydrogen produced to the molecule used for transport and $C_{reconversion,z,y}$ the reconversion cost after transportation. Key input data for these cost can be found in (Deloitte 2023).

Contacts

Dr. Johannes Trüby
jtruby@deloitte.fr
+33 1 55 61 62 11
Partner, Economic Advisory –
Energy and Climate Economics, Deloitte

Dr. Manuel Villavicencio
mvillavicencio@deloitte.fr
+33 1 40 88 70 42
Director, Economic Advisory –
Energy and Climate Economics, Deloitte

Dr. Johannes Brauer
jbrauer@deloitte.fr
+33 1 55 61 52 05
Manager, Economic Advisory –
Energy and Climate Economics, Deloitte

Aurélien Ailleret
aailleret@deloitte.fr
+33 1 58 37 94 20
Senior Consultant, Economic Advisory –
Energy and Climate Economics, Deloitte

Clémence Lévêque
cleveque@deloitte.fr
+33 1 55 61 43 32
Consultant, Economic Advisory –
Energy and Climate Economics, Deloitte

Marc de Froidefond | mdefroidefond@deloitte.fr | +33 1 55 61 28 72
Consultant, Economic Advisory – Energy and Climate Economics, Deloitte France

Jules Chabanis | jchabanis@deloitte.fr | +33 1 40 88 28 00
Consultant, Economic Advisory – Energy and Climate Economics, Deloitte France

Anoushka Hooda | anohooda@deloitte.fr | +33 1 40 88 28 00
Consultant, Economic Advisory – Energy and Climate Economics, Deloitte France

Deloitte.