

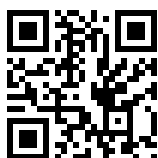
Methodology for assessing greenhouse gas emissions savings from low-carbon fuels



Policy Department for Transformation, Innovation and Health
Directorate-General for Economy, Transformation and Industry

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Abstract

The Delegated Act on low-carbon hydrogen establishes a harmonised, transparent framework, defining fuels in a technology-open way. It is essential for a functioning hydrogen market but does not create demand or financial incentives. Achieving emissions reduction targets will hinge on robust methane emissions measurement and reporting. Costs will remain above unabated hydrogen, shaped mainly by natural gas and electricity prices.

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LIST OF ABBREVIATIONS

| | |
|---------------|--|
| ATR | Autothermal Reforming |
| CAPEX | Capital Expenditure |
| OPEX | Operational Expenditures |
| DA | Delegated Act |
| CCS | Carbon capture and storage |
| CCU | Carbon capture and utilisation (chemically bound in long-lasting products) |
| IEA | International Energy Agency |
| RFNBO | Renewable Fuels of Non-Biological Origin |
| LCF | Low-carbon fuels |
| NG | Natural gas |
| LNG | Liquified Natural Gas |
| GHG | Greenhouse gas |
| RED | Renewable Energy Directive |
| RCF | Recycled carbon fuels |
| ETS | Emissions Trading System |
| WTW | Well-to-wheel |
| JRC | Joint Research Centre |
| GWP | Global Warming Potential |
| UNFCCC | United Nations Framework Convention on Climate Change |
| OCI | Oil Climate Index |
| IOGP | International Association of Oil & Gas Producers |

| | |
|----------------|--|
| PPA | Power Purchase Agreement |
| CNG | Compressed Natural Gas |
| JEC | Joint Research Centre of the European Commission–Eucar–Concawe |
| ENVI | Committee on the Environment, Climate and Food Safety |
| ITRE | Committee on Industry, Research and Energy |
| SMR | Steam Methane Reforming |
| LCOH | Levelised Cost of Hydrogen |
| T&S | Transport and Storage |
| PEM | Proton Exchange Membrane |
| SOEC | Solid Oxide Electrolyser Cell |
| POX | Partial oxydation |
| CCGT | Combined Cycle Gas Turbine |

EXECUTIVE SUMMARY

Background

On 8 July 2025, the European Commission adopted a Delegated Act C(2025) 4674, supplementing Directive (EU) 2024/1788 on the internal markets for renewable gas, natural gas and hydrogen, which is currently subject to scrutiny by the European Parliament and the Council. The Act defines the methodology to calculate greenhouse gas (GHG) emissions savings from Low-Carbon Fuels (LCFs), with particular relevance for low-carbon hydrogen. It aligns with the earlier adopted methodology for renewable fuels of non-biological origin (RFNBOs) and establishes a minimum reduction of 70% GHG emissions savings compared to the unabated fossil fuel comparator.

This Delegated Act (DA) comes in the context of the EU Hydrogen Strategy (2020) and REPowerEU (2022), which set ambitious deployment goals for renewable hydrogen. Following the adoption of the Hydrogen and Gas Market Directive, the role of low-carbon hydrogen and fuels was recognised as one of the levers to advance decarbonisation efforts in sectors where electrification would offer limited solutions. However, a critical missing piece was the EU-wide framework to assess their GHG emissions performance. Establishing clear standards, embedded in an enabling regulatory framework, is essential to foster an environment that provides investment certainty and safeguards environmental integrity for development and deployment of clean hydrogen solutions.

The Delegated Act aims to provide a harmonised and transparent regulatory framework for low-carbon hydrogen and fuels, ensure comparability with renewable hydrogen and fuels, and facilitate the scaling of low-carbon hydrogen and fuel supply in the EU. It has important implications for investment decisions and market signals, production costs, and the environmental integrity of Europe's hydrogen economy.

Aim

This report, prepared at the request of the European Parliament's Committee on Industry, Research and Energy (ITRE), aims to answer the following questions:

- Which production pathways are included and excluded by the methodology provided by the draft Delegated Act?
- Does the Delegated Act enable the hydrogen economy by providing incentives to produce or import sufficient volumes of hydrogen in/to the European Union?
- Is the Delegated Act sufficiently addressing fossil fuel emissions?
- What are the price and cost expectations of such hydrogen based on this methodology?

Key Findings

Following the analysis, key findings include:

- a. Which production pathways are included and excluded by the methodology provided by the draft DA?

The DA defines low-carbon fuels in a technology-neutral way, measuring life cycle emissions across the full value chain, including indirect ones. The key criterion is that fuels must be at least 70% below the unabated fossil-fuel comparator of 94 gCO₂eq/MJ, i.e., below 28.2 gCO₂eq/MJ. The DA does not prescribe specific production pathways.

There are two main production routes: (i) fossil pathways, using fossil fuels with carbon capture and storage or utilisation, and (ii) electrolytic pathways, producing hydrogen from water and electricity. The DA allows certification for hydrogen made with partly non-renewable electricity (e.g. nuclear).

Hydrogen leakage will be included once scientific consensus exists on its warming impact. Because hydrogen leaks more easily than methane, it poses a potential risk as infrastructure expands and should be addressed as early as possible.

- b. Does the Delegated Act enable the hydrogen economy by providing incentives to produce or import sufficient volumes of hydrogen in/to the European Union?

The Delegated Act (DA) is a regulatory enabler, not a market driver. It does not create demand, set production targets, or provide financial incentives for hydrogen. Instead, it establishes a harmonised EU-wide accounting and certification methodology for low-carbon fuels, giving developers, investors, importers, and Member States regulatory certainty about what qualifies as low-carbon hydrogen. This reduces investment risk, facilitates cross-border trade, and prevents fragmentation from diverging national standards. In short, the DA lays the groundwork for a functioning low-carbon hydrogen market but does not itself stimulate production or imports. Most current EU support is targeted at renewable hydrogen (RFNBOs), so the DA's effect on low-carbon hydrogen will depend heavily on whether additional policy instruments are created at EU or national level.

- c. Does the Delegated Act sufficiently address fossil fuel emissions?

The Delegated Act (DA) defines rules for both fossil-based hydrogen with CCS and electrolytic hydrogen, but its adequacy in addressing fossil emissions is decisive for credibility. Low-carbon hydrogen climate integrity will hinge on robust methane (CH₄) emissions measurement and reporting data.

- Natural gas pathways:
 - Upstream CH₄ emissions: The DA includes methane intensity in life cycle GHG accounting. The default leakage rate (0.88%, 0.190 g CH₄/MJ NG) is reasonable but not conservative, meaning some higher-emission sources may still meet thresholds by reporting default values. Accurate and comprehensive reporting under the Methane Regulation is key.

- Upstream natural gas CO₂ emissions: The DA's CO₂ default value of 4.9 g CO₂/MJ NG is broadly consistent with the EU-mix value in the 2020 JEC Well-to-Wheels report and with the IEA's estimate of the global average. Like the methane default, the CO₂ default can be characterised as justifiable but is not strongly conservative.
- LNG emissions: LNG is more emission-intensive than pipeline gas due to liquefaction and transport losses. Current defaults do not include LNG-specific values, creating uncertainty and underreporting risks without standardized measurement.
- Electrolytic pathways:
 - Emissions depend on the electricity mix. Four calculation methods are allowed, with nuclear recognised as a low-carbon source. Countries with clean grids (e.g. Sweden, France) can already comply but fossil-heavy grids (e.g. Germany, Poland) require a part of the supply to come from renewable PPAs or direct connection to reduce the average of the input mix.

The DA is a step forward in assessing emissions across the whole hydrogen supply chain. However, relying on reasonable but non-conservative CH₄ and CO₂ defaults, and the omission of LNG-specific default values, risks underestimating methane emissions where actual data is lacking. Its effectiveness will depend on strict enforcement and accurate reporting under the methane regulation. Electrolytic hydrogen already meets thresholds in low-carbon grid regions, while fossil-heavy grids need dedicated renewable PPAs or direct connections to renewable plants in accordance with the RFNBO DA.

d. What are the price and cost expectations of hydrogen based on this methodology?

Complying with LCF emissions savings raises costs compared to unabated "grey" hydrogen, since producers must add carbon abatement technologies (CCS or CCU) or restrict electrolytic production to low-emission hours if the grid intensity exceeds the minimum threshold.

- Blue hydrogen (natural gas with CCS):
 - Estimated costs are in the range 3.5–6.5 €/kg, with the lower end reflecting current gas prices (40 €/MWh). At this level, the cost is 3.5 €/kg, roughly 60% more expensive than grey hydrogen (2.2 €/kg).
 - Cost variations across Member States are minimal, as natural gas price is the main contributor to blue hydrogen cost. CO₂ transport and storage costs remain uncertain and depend on utilisation for cost reduction.
 - Future gas price volatility will be the main factor influencing blue hydrogen costs.
- Electrolytic low-carbon hydrogen:
 - Current costs are 6–8 €/kg, depending on electrolyser and grid costs. Electricity makes up about half or more of total costs.
 - Falling electrolyser prices allow greater flexibility to use cheap, low-emission electricity, which could allow costs to fall below 3 €/kg. However, the speed of progress is uncertain.

- In fossil-heavy grids, production hours are limited to meet LCF rules, which would raise costs due to lower utilisation rates, unless electricity supply is partially supplemented by renewable PPAs, bringing down the average emissions of the input mix. This increases average electricity costs but boosts RFNBO compliant output.

Blue hydrogen is likely the cheapest near-term option, though tied to volatile gas prices. Electrolytic hydrogen will become more competitive as electrolyser costs fall, low-carbon electricity expands, but remains costlier today and highly dependent on power prices.

1. KEY ELEMENTS OF THE DELEGATED ACT

KEY FINDINGS

The Delegated Act (DA) is meant to complement the Directive (EU) 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen. Its approach is aligned with previous legislation defining the EU's standards for renewable hydrogen and renewable fuels of non-biological origin (RFNBO), as set out in the Renewable Energy Directive (EU) 2023/2413.

The DA defines low-carbon fuels in a technology-agnostic way, with a methodology to calculate the emissions intensity of fuels that includes life cycle emissions across the entire value chain, as well as indirect emissions. This definition is technology-open since it focuses on outcomes rather than pathways. The decisive criterion is that the final product is below the carbon intensity threshold, namely it must be 70% lower than the unabated fossil reference. As such, there are two main pathways for producing low-carbon fuels:

1. Fossil pathways: using fossil fuels with carbon capture and storage or utilisation to reduce the emissions. The methodology indicates that for fossil emissions accounting, producers have the obligation to provide real data but if not feasible, they can use default data. For LNG emissions, no default value is currently in place as data are missing and will be mandatory to collect in the future. For the first years importers will have to provide GHG intensities based on estimates and literature.
2. Electrolytic pathways: using water and electricity to power electrolytic processes to generate hydrogen. The DA gives projects seeking to produce hydrogen with not fully-renewable electricity (e.g., nuclear) a pathway to certification and regulatory certainty, aligned with and supplementary to RFNBO. The European Commission shall assess the impact of the potential introduction of alternative approaches for recognising low-carbon electricity from nuclear power plants in 2028.

Hydrogen leaks are excluded from the methodology and the DA indicates that they will be added as soon as there is scientific consensus about hydrogen's GWP. Given hydrogen's smaller molecular size and greater diffusivity, it is even more prone to leakage than methane. If not addressed proactively, hydrogen leakage could become a significant issue as new infrastructure is developed.

The DA supplements the Hydrogen and Gas Market Directive (EU) 2024/1788 by specifying a methodology for assessing GHG emissions savings from low-carbon fuels placed into the EU market. The Directive aims to facilitate the penetration of renewable gas and low-carbon gas and hydrogen into the EU energy system, to allow renewable gas and low-carbon gas and hydrogen to play an important role in achieving the Union's 2030 climate objectives and climate neutrality by 2050.

The DA's scope is "low-carbon fuels other than recycled carbon fuels", which according to the definitions in the Directive (EU) 2024/1788 are low-carbon hydrogen, and synthetic gaseous and liquid

fuels the energy content of which is derived from low-carbon hydrogen¹, that meet the greenhouse gas emission reduction threshold of 70% compared to the reference value. This value is called the fossil fuel comparator to measure greenhouse gas savings for renewable fuels of non-biological origin set out in the methodology adopted pursuant to Article 29a(3) of Directive (EU) 2018/2001. The fossil fuel comparator is 94 grams of CO₂ equivalent per mega joule of energy (94 gCO₂eq/MJ), which represents the average emissions intensity of conventional fuels (petrol, diesel, natural gas, etc.). This means the maximum allowable carbon intensity for low-carbon fuels is 28.2 gCO₂eq/MJ (on a lower heating value basis).

1.1. Methodology to calculate emissions intensity of fuels

Recital 1 of the Delegated Act states that the accounting methodology should take into account:

- full life cycle emissions, such as from the energy used in the production process (but not the emissions from the manufacture of the machinery itself),
- indirect emissions resulting from the diversion of rigid inputs (defined below) from producing low-carbon fuels,
- methane upstream emissions (an important consideration, as methane is a potent greenhouse gas, which means that leakage can negate the emissions savings from carbon capture and storage),
- actual carbon capture rates.

The methodology applied by the DA requires GHG emissions from the production and use of low-carbon fuels other than recycled carbon fuels to be added up using a formula similar to the formula used by the Life Cycle Analysis (LCA) in the Renewable Energy Directive 2023/2413. The overall emission intensity is the sum of:

1. Emissions associated with inputs – This covers all the material feedstock and energy (electricity and heat) used to make low-carbon hydrogen. Inputs are split into two types: 'elastic' and 'rigid' inputs².
2. Emissions from processing – This includes emissions associated with the on-site combustion of fossil fuels and from any on-site methane leaks during production. It also takes into account any CO₂ that is captured and stored from the site (accounted for under e_{ccs}) or used (under

¹ Low-carbon fuels include synthetic gaseous and liquid fuels derived from low-carbon hydrogen, such as low-carbon methanol, synthetic methane, and ammonia. This category does not include biomethane or other biofuels, which are covered separately under REDIII. Renewable hydrogen and renewable fuels of non-biological origin (RFNBOs) are also defined under REDIII.

² Rigid and elastic inputs are defined in the Delegated Act Annex. Rigid inputs are those whose supply cannot be expanded to meet extra demand. Thus, all inputs qualifying as a carbon source for the production of recycled carbon fuels are rigid, as well as outputs produced in a fixed ratio by an incorporated process and which represent less than 10% of the economic value of the output. If it represents 10% or more of the economic value, it shall be treated as elastic. In principle, elastic inputs are those whose supply can be increased to meet extra demand. Petroleum products from refineries fall into this category because refineries can change the ratio of their products.

e_{ccu} term)³, and any CO₂ released at the end of the life cycle of co-products (for example, CO₂ released when black carbon from methane pyrolysis is disposed of).

3. Emissions from fuel combustion – These are the greenhouse gases released when the fuel is actually used. For fuels containing non-biogenic elemental carbon (generally carbon capture and utilisation (CCU) fuels), this includes stoichiometric CO₂ emission from fuel use, which means that is inevitably released when the fuel is burned. For all fuels, it includes expected methane and nitrous oxide emissions that occur during combustion.
4. CCS credit – A CCS credit is attributed where process CO₂ emissions are captured and permanently stored.
5. CCU credit – A CCU credit is attributed where process CO₂ emissions are captured and permanently chemically bound in long-lasting products.

In the case that more than one product is generated by a process, life cycle emissions are to be allocated between the products, following the same rules as are already used in the RFNBO and Recycled Carbon Fuels (RCF) Life Cycle Assessment methodology.

The greenhouse gas emissions intensity of low-carbon fuels shall be determined by dividing the total emissions of the process covering each element of the formula by the total amount of fuel stemming from the process and shall be expressed in terms of grams of CO₂ equivalent per MJ of fuel (gCO₂eq/MJ fuel).

1.2. Production pathways included and excluded in the DA

The DA establishes a technology-open approach that does not limit low-carbon fuel production pathways as long as the 70% GHG emissions reduction compared to the fossil fuel comparator is met. The methodology does not prescribe specific low-carbon fuel production technologies. Therefore, any fossil-based production or non-fully renewable electrolytic pathways can qualify if the GHG emissions savings calculated under the Annex rules meet the minimum threshold.

While the DA is technology-neutral, the low-carbon fuel production pathways that are likely to be most relevant⁴ can be grouped into two categories:

1. Fossil pathways – These are hydrogen production pathways that use fossil fuels as feedstock, paired with carbon capture and storage or utilisation technologies, and can be subdivided into two categories:
 - a. Natural gas pathways: The most relevant technologies include Steam Methane Reforming⁵ (SMR) and Autothermal Reforming (ATR).

³ e_{ccs} and e_{ccu} refer to the net emissions savings from carbon captured and stored and net emission savings from carbon captured and permanently chemically bound in long-lasting products, respectively.

⁴ Besides the two groups of pathways discussed here there is for instance also the possibility to use nuclear heat to directly produce low carbon hydrogen without electrolysis which is also covered by the DA. However, this pathway and others not treated here are at a lower stage of technological maturity at this time.

⁵ Unabated steam methane reforming is currently the dominant production pathway for hydrogen in Europe: over 550 hydrogen production sites are currently operational in Europe, with a total production capacity of 11 million tonnes per year. Over 50% of this production is

- b. Other fossil fuels pathways: These are processes that use as feedstock and energy inputs other fossil fuels than natural gas (e.g., coal gasification).
2. Electrolytic pathways - Hydrogen produced in electrolyzers from electricity that cannot qualify as fully renewable in accordance with to Article 27(6), second and third subparagraph, of Directive (EU) 2018/2001. Nuclear energy is eligible to produce, however, the approach will be assessed in 2028.

Beyond hydrogen, other low-carbon fuels can also be produced, such as ammonia or e-fuels. In these cases, nitrogen or carbon is captured from the atmosphere or point sources and added to hydrogen to produce a fuel. These fuels have practical advantages, such as being easier to transport and store than pure hydrogen. However, these fuels require more steps to produce and are therefore more energy-intensive, making them more costly and emissions-intensive than hydrogen alone. Because of the criteria for a fuel to qualify as low-carbon (illustrated in the calculation examples in the next sections of this report), there will be cases where the emissions reductions of low-carbon hydrogen would be close to the threshold. For some of these cases, it would be challenging to produce a hydrogen derivative (e.g., ammonia or LCF) that would meet the maximum allowed carbon intensity. However, assuming emissions are significantly low across the entire value chain, or that the electricity grid has very low carbon intensity, there is potential to produce hydrogen derivatives that comply with the standard. For more information, please see section 3 on Fossil Emissions.

Table 1: Relevant low-carbon fuel production pathways

| Pathways | Technologies | Feedstocks (not exhaustive) |
|--------------------|---|--|
| Natural gas | Steam methane reforming + carbon capture and storage/utilisation, autothermal reforming + carbon capture and storage/utilisation, methane pyrolysis, partial oxidation (POX) + carbon capture and storage/utilisation | Natural gas (pipeline or LNG) |
| Other fossil fuels | Gasification + CCS/CCU | Coal, petroleum coke / heavy residue, refinery gas |
| Electrolytic | Proton Exchange Membrane (PEM) electrolyzers, Solid Oxide Electrolyzer Cell (SOEC) electrolyzers, alkaline electrolyzers | Water |

Source: Future Cleantech Architects

Note: The pathways and feedstocks provided in the table above are not exhaustive. For a complete list of feedstocks, please see Delegated Act Annex Table 1: Default life cycle GHG emissions of different energy inputs, expressed in g of substance per MJ of product.

concentrated in six EU countries: Germany, the Netherlands, Poland, Spain, Italy, and France. This makes up ~3% of the EU's total annual emissions.

Recycled carbon fuels are outside the scope of this DA. In Directive (EU) 2018/2001, these are defined as “liquid and gaseous fuels that are produced from liquid or solid waste streams of non-renewable origin which are not suitable for material recovery in accordance with Article 4 of Directive 2008/98/EC, or from waste processing gas and exhaust gas of non-renewable origin which are produced as an unavoidable and unintentional consequence of the production process in industrial installations”.

1.3. Hydrogen Leaks

Quantifying hydrogen leakage is fraught with uncertainty. However, we can draw an instructive parallel with the methane (natural gas) industry. Despite decades of experience, methane infrastructure continues to face persistent leakage issues.

For now, the methodology does not include hydrogen’s global warming potential (GWP) due to uncertainty around the value of this parameter. The DA calls for this to be added as soon as scientific evidence has matured. This is an important consideration in the life cycle assessment because hydrogen can leak between its point of production and use. Recent scientific studies estimate hydrogen’s GWP to be around 30–40 times higher than that of carbon dioxide over a 20-year period, though the precise value remains subject to ongoing research.⁶

⁶ For further information on hydrogen leaks from infrastructure and their climate impact, see Esquivel-Elizondo *et al* (2023), *Wide range in estimates of hydrogen emissions from infrastructure*, *Frontiers in Energy Research*. <https://doi.org/10.3389/fenrg.2023.1207208>.

2. DELEGATED ACT IMPACT ON HYDROGEN ECONOMY

Hydrogen is a decarbonisation enabler for sectors of the economy where electrification offers limited effective decarbonisation options, such as aviation and shipping. Hydrogen does not inherently contribute to energy security, as the lowest cost hydrogen production pathways rely on natural gas; and even for electrolytic hydrogen (i.e., hydrogen produced from water using electricity in an electrolyser), its challenging physical properties mean that it remains difficult to store or transport,⁷ especially via seaborne routes (i.e., imports), which reduces the extent to which hydrogen imports are likely to be used to diversify energy sourcing.

Low-carbon hydrogen and fuels production will hinge on the availability of low-carbon (but not fully renewable) electricity, and on carbon abatement technologies such as CCU and CCS, and their respective infrastructure, and will only become commercially relevant with an enabling policy framework to incentivise its development and deployment.

2.1. Role of the Delegated Act

The Delegated Act does not by itself create demand or set demand volumes for low-carbon hydrogen and fuels in the EU. The main function of this Delegated Act is to establish a harmonised EU-wide accounting methodology and certification framework for low-carbon fuels. It creates certainty for developers to proceed with low-carbon fuels and hydrogen projects. This is a necessary building block for developing a properly functioning market: it provides regulatory transparency and clarity on the GHG emissions accounting methodology, which in turn provides clarity to low-carbon fuel producers, both inside and outside the EU, by removing regulatory uncertainty on what qualifies as low-carbon hydrogen and fuels. This is necessary in order to create an enabling framework, laying the conditions for the development of a new segment of the hydrogen market, giving common EU accounting rules for producers, importers, investors, and users, so that they can better trade, certify, or claim emissions reductions credibly.

By removing regulatory uncertainty around the GHG emissions reduction accounting methodology on what would qualify as low-carbon hydrogen and fuels, the DA removes risks for investment in these low-carbon fuel projects (such as 'blue' hydrogen with CCS).

The DA also provides clarity to Member States designing schemes intended to support the development of low-carbon hydrogen and fuels, enabling the alignment of national measures with an EU-wide GHG accounting methodology and certification approach. It can help strengthen the Single Market with less fragmentation due to fewer different national standards.

However, the DA is not a market-pull instrument or a financial incentive by itself. Rather, if incentives are put in place by the EU or Member States in the future, the DA will provide clarity about which fuels

⁷ According to the IEA, hydrogen trade remains minimal, and more than 80% of the world's hydrogen is still produced and consumed onsite. This is due to hydrogen's challenging properties, which result in high efficiency losses and costs for transport modalities other than pipelines. For further information see: <https://www.iea.org/reports/global-hydrogen-review-2024/trade-and-infrastructure>.

are eligible to receive them⁸. It does not create production targets, nor price-support mechanisms such as contracts for difference, subsidies, or auctions to reward stakeholders for developing low-carbon hydrogen, nor binding quotas or budgetary support for high Capital Expenditure (CAPEX) or Operational Expenditures (OPEX). Consequently, it cannot on its own guarantee the production or import of sufficient hydrogen volumes into the EU.

Instead, it creates the conditions for projects to qualify for such instruments under EU or national schemes. These mechanisms are provided by other European Union policies, and primarily focused on renewable hydrogen, such as the Hydrogen Bank, in addition to national policy mechanisms from Member States. Fostering a low-carbon hydrogen market will depend on additional policy instruments and not solely on the DA accounting methodology. The DA only makes financial and demand-side instruments effective.

As indicated above, most of the current EU instruments and targets are designed to support renewable hydrogen. Therefore, its development will depend on Member States and the EU policy mechanisms to support low-carbon hydrogen, if and where such schemes are in force. The default values for GHG emissions reduction, harmonised with the RFNBO approach, can serve as a transitional instrument to launch the first wave of early low-carbon fuels and hydrogen projects to qualify as LCF and move forward.

2.2. Industrial and market implications

From an industrial perspective, Europe already hosts 550 hydrogen production sites based on natural gas reforming. Some of these facilities are located in industrial regions and near prospective geological CO₂ storage sites in the North Sea for instance, or in depleted gas fields. These installations could be considered potential candidates for conversion to low-carbon hydrogen with CCS. However, a distinction should be made between hydrogen end use as an indispensable feedstock (e.g., for ammonia production) or as fuel. Most of the hydrogen produced in Europe today is used as an industrial feedstock for fertilisers or fuel production in refineries. The DA provides existing facilities seeking to produce low-carbon fuels with regulatory certainty to access support schemes for greenfield facilities or retrofitting, and can therefore help industrial regions to attract investment and maintain jobs in those industrial sectors⁹.

For electrolytic LCF production, the addition of a fourth electricity-accounting option included in the DA also allows developers to plan operations more closely adapted to local grid emission conditions. The methodology makes it possible to produce low-carbon hydrogen more frequently at times when electricity tends to be both low-cost and low emissions intensity, without the need for a renewable PPA due to stricter requirements like additionality.

⁸ Compliant low-carbon fuels benefit from favourable treatment under the EU ETS, as the Monitoring and Reporting Regulations (MRR) assigns a zero-emissions rating. This mainly affects synthetic derivatives, creating a value signal once the DA is adopted, while hydrogen used in ETS installations is generally already zero-rated.

⁹ Projects such as the H-vision development in Rotterdam aim to develop low-carbon hydrogen in existing industrial facilities by using residual gases as a feedstock. The resulting low-carbon hydrogen can now be used to generate heat to complete industrial processes. For more information see: <https://www.h-vision.nl/en>.

The DA also puts the low-carbon hydrogen produced in parallel to RFNBO hydrogen with electricity from a renewable PPA on a clear footing. This gives electrolyzers further operational flexibility to use electricity that cannot be fully counted as renewable under RED III, but that still meets the 70% emission savings threshold. In sum, this could be seen as enabling a complementary value signal for the non-renewable part of the production and its expansion, potentially resulting in the DA complementing the RFNBO rules and enhancing the value signal for the deployment of electrolyzers. However, this will depend on a complementary policy framework for electrolytic vs. fossil-based low-carbon hydrogen.

Producers of electrolytic low-carbon hydrogen would need such an enabling framework in place to address the non-profitable part of the cost of production, because it will be higher than that of grey hydrogen but also blue hydrogen for some time¹⁰. If blue hydrogen sets the reference price in the low-carbon hydrogen market, electrolyzers will be much more reliant on RFNBO-related incentives to remain competitive. While this dynamic could slow electrolyser development in the Union in the near term, global technological learning effects and declining renewable electricity costs are expected to reduce the cost of electrolytic hydrogen over time.

Still, for 'pure LCF' (i.e., low-carbon hydrogen that is not co-produced with RFNBO), blue hydrogen will likely be able to outcompete grid-based non-renewable electrolytic hydrogen for the foreseeable future (see Section 4 of this report). LCF electrolytic hydrogen will likely emerge mostly as a co-product of RFNBO projects, since it is costlier but classified identically to blue hydrogen with CCS or CCU, so it will lack dedicated policy support if policies are solely based on this classification. Unless additional instruments are introduced to create differentiated value signals, the DA could effectively facilitate blue hydrogen's role in the market, while electrolytic hydrogen growth will depend on RFNBO-specific mechanisms. The DA thus clarifies rules but leaves the balance between blue and electrolytic low-carbon hydrogen to be determined by broader EU and national policy choices.

2.3. State of clean hydrogen production in Europe

At present, the combined effect of policy mechanisms in place to support RFNBO production and uptake is only nascent. The total dedicated electrolysis capacity in Europe by the beginning of Q4 2024 was 385 MW_e, equivalent to 0.064 million tonnes of annual production¹¹. The total hydrogen production volumes of all projects that had reached the stage of final investment decision were equivalent to 2600 MW_e¹² or about 0.43 million tonnes per year. For comparison, the total grey hydrogen demand in Europe in 2023 was 7.9 million tonnes, almost exclusively for industrial feedstock (as opposed to transport applications, which are also only in a nascent stage at present), while the EU Hydrogen Strategy target was 6 GW_e for renewable hydrogen electrolyser deployed capacity by 2024.

Existing streams of byproduct hydrogen are in part RFNBO eligible, but currently have a low level of uptake for new applications, since they are not being rerouted to downstream transport sectors. This is another statistic that is potentially indicative of the effect of incentive mechanisms and the state of

¹⁰ This excludes the aforementioned byproduct RFNBO and LCF hydrogen production streams with low opportunity costs for repurposing.

¹¹ Data from 2024 Hydrogen Europe report, which assumes 63% conversion efficiency and 100% capacity factor.

¹² "MW_e" denotes the electrical input power of the electrolyzers. This contrasts with the thermal power output of the hydrogen produced, commonly denoted "MW_{th}".

the market. The capacity to produce electrolytic RFNBO hydrogen in the chlor-alkali industry can be estimated to be around 0.078 million tonnes per year based on 2023 data¹³, i.e. it is slightly higher than the dedicated electrolysis capacity that was installed in Q4 2024. Once the DA rules come into force, this production will be augmented by LCF-eligible hydrogen where the grid carbon intensity is low enough as well¹⁴. The main product of the chlor-alkali industry is chlorine, but hydrogen is generated as an unavoidable byproduct. Accordingly, where it cannot be used for higher-value applications like co-located chemical processes, it is often burned for the generation of heat and steam, or it is vented to the atmosphere¹⁵. Some of these applications present low-cost opportunities for retargeting the RFNBO hydrogen stream, e.g., replacing the combustion of hydrogen with electrified heating. Effective incentives for the uptake of RFNBO as well as low-carbon hydrogen, should have a relatively strong initial effect to catalyse the uptake of this hydrogen in downstream sectors.

¹³ Based on the capacities installed at the end of 2023, the industry-wide utilization rate (62.2%) (Eurochlor 2024), and the fraction of renewables in the electricity mix of the respective countries two years prior to 2023, i.e. 2021 (Eurostat 2025). Accounting is assumed to be using the pathway to RFNBO production “set out in the fourth subparagraph of Article 27(3), [which] determines the share of renewable hydrogen based on the share of renewable electricity in the country of production in the year n-2.” (DG ENER 2024). Total production of hydrogen in the chlor-alkali industry (as opposed to the estimated RFNBO eligible fraction) was 0.201 Mt in 2023 (Eurochlor 2024).

¹⁴ For example, all of the hydrogen produced in the chlor-alkali industry of France will have LCF status.

¹⁵ According to data from Eurochlor, in 2023, 34.5% of the hydrogen byproduct was deployed in co-located chemical process, 7.5% was used for heat generation and 33.1% for steam production, and 12.8% was vented to the atmosphere. https://www.eurochlor.org/wp-content/uploads/2024/08/Chlor_Alkali_Industry_Review_2023_2024.pdf#page=25.00

3. FOSSIL EMISSIONS ACCOUNTING IN THE DELEGATED ACT

KEY FINDINGS

The analysis distinguishes emission pathways for low-carbon hydrogen production, separating fossil-based (natural gas with CCS) from electrolytic methods. For natural gas pathways, significant emissions arise from upstream activities such as methane leakage during extraction and transport, and CO₂ from consumed energy, with Liquefied Natural Gas (LNG) adding further complexity due to its energy-intensive liquefaction and transportation. Conversely, for low-carbon hydrogen produced via electrolysis, emissions are primarily associated with the electricity used in the process.

1. Upstream natural gas CH₄ emissions: The DA requires methane intensity to be included in life cycle GHG accounting. Methane leakage during natural gas extraction, processing, and transport is a critical emissions source, with the DA default leakage rate of 0.88% (0.190 g CH₄/MJ NG) considered justifiable but not highly conservative, potentially allowing some higher-intensity sources to meet LCF thresholds. This depends on the enforcement of the new methane reporting under the methane regulation.
2. Upstream natural gas CO₂ emissions: The DA's CO₂ default value of 4.9 gCO₂/MJ NG is broadly consistent with the EU-mix value in the 2020 JEC Well-to-Wheels report and with the IEA's estimate of the global average. Like the methane default, the CO₂ default can be characterised as justifiable but is not strongly conservative.
3. LNG's emissions: LNG has a significantly higher typical emissions intensity than natural gas supplied by pipeline, primarily due to the energy requirements of liquefaction and methane losses during transport, yet current DA default values for natural gas inputs do not include these specific LNG-related default emission values. If not measured in accordance with the methane regulation, reporting relies on estimated data and literature, but in the absence of a standardised approach, this creates uncertainty and a risk of underreporting.
4. Electrolytic hydrogen's electricity dependence: The GHG intensity of electrolytic hydrogen is predominantly determined by its electricity source. Under the DA rules, there are four options to calculate electricity emissions (annual average, day-ahead forecast, full-load hour benchmark, hourly marginal plant). Nuclear power is identified as a key non-RFNBO LCF source, capable of producing hydrogen well within the implied threshold. Countries like Sweden, Finland, France, Denmark and Lithuania can already produce hydrogen that meets the LCF threshold using average grid electricity. Countries with fossil-heavy grids (like Germany and Poland) cannot meet thresholds with grid electricity alone and would need dedicated renewable PPAs or direct connections to renewable plants.

The findings underscore the complexity and gaps in current frameworks for assessing low-carbon hydrogen production pathways. For the natural gas pathway, the analysis shows that meeting the 70% threshold effectively requires high capture rates, assuming robust methane intensity reporting helps exclude the most carbon-intensive natural gas sources. As a result, the eligibility of low-carbon hydrogen from natural gas will depend on accurate and reliable methane emissions accounting. The natural gas defaults for CO₂ and CH₄ can be characterised as justifiable but not strongly conservative. For electrolytic hydrogen, the threshold is already achievable in some regions with low-carbon electricity mixes, while fossil-heavy grids require dedicated renewable electricity

Fossil-based emissions arise at different points along the hydrogen supply chain, depending on the production pathway. For natural gas with carbon capture and storage (NG+CCS) and other fossil fuels with CCS pathways with high capture rates, emissions originate mostly from upstream activities like extraction, processing and transportation. The biggest contributors are carbon dioxide (CO₂) associated with consumed energy, and methane (CH₄) being vented or leaking during extraction and transport. In contrast, for low-carbon hydrogen produced via electrolysis, GHG emissions are primarily associated with the electricity used in the process.

Section 3.2 addresses the natural gas pathway, which is by far the largest source of global hydrogen production, focusing on two priority issues: the extent of upstream methane emissions during extraction and transport, and the treatment of LNG within the transport supply chain.

Section 3.3 covers low-carbon hydrogen produced via electrolysis and is structured around two main themes: insights on the use of non-RFNBO-eligible electricity and considerations for producing mixed RFNBO and low-carbon hydrogen.

3.1. Natural gas pathway

3.1.1. Overview of natural gas emissions factor options

If data is available, greenhouse gas emissions from natural gas (including LNG) must be calculated using actual production data, covering all emissions across the entire supply chain (from energy extraction to processing and transport), but excluding combustion emissions.

Methane intensity calculations must include both production and transport emissions, with data sourced as follows:

- EU-produced inputs: Methane emissions reported by producers and asset operators under Methane Regulation (EU) 2024/1787.
- Imported inputs or those used abroad: Methane emissions reported by importers under Methane Regulation (EU) 2024/1787, supported by Methane Transparency database values and operator data.

If methane GHG intensity cannot be determined due to a lack of data availability or if the natural gas is used for process energy only and does not increase the fuel's heating value, then the default upstream methane emission values from Annex Part B may be used. The DA also clarifies that the default

emissions intensities for natural gas as an input from Annex Part B do not include emissions associated with liquefaction and transport of LNG. In other words, the DA does not include default emissions for liquefaction and transport of LNG.

3.1.2. Comparing the DA default values with other studies

For the purpose of this analysis, we relied on the latest data from JEC and the IEA, as alternative sources could not be consulted within the available time frame. The JEC WTW v5 database includes natural gas supply emissions values in the well-to-tank data. For non-LNG pathways, emissions come from production, pipeline transport, high-pressure distribution and Compressed Natural Gas (CNG) compression and dispensing for retail. Using a simplified approach that includes high pressure distribution but excludes compression for retail, the CO₂ emissions are¹⁶:

- 5.16 gCO₂/MJ for EU mix natural gas, transported an average of 2400 km by pipeline;
- 8.95 gCO₂/MJ for imported natural gas from Russia transported 5000 km by pipeline;
- 7.65 gCO₂/MJ for imported natural gas from the Middle East transported 4000 km by pipeline.

These values are all higher than the default value for upstream CO₂ of 4.9 gCO₂/MJ in the DA.

For methane emissions, the reported values are:

- 0.13 gCH₄/MJ for the EU mix,
- 0.20 gCH₄/MJ for Russian imported gas
- 0.167 gCH₄/MJ for Middle Eastern imported gas.

Compared with the DA default of 0.190 gCH₄/MJ, methane emissions are lower for the EU mix and Middle Eastern gas, but slightly higher for Russian gas.

The IEA World Energy Outlook 2023 reports a global average supply GHG intensity for natural gas of about 12 gCO₂eq/MJ, slightly above the sum of the DA defaults (10.2 gCO₂eq/MJ)¹⁷.

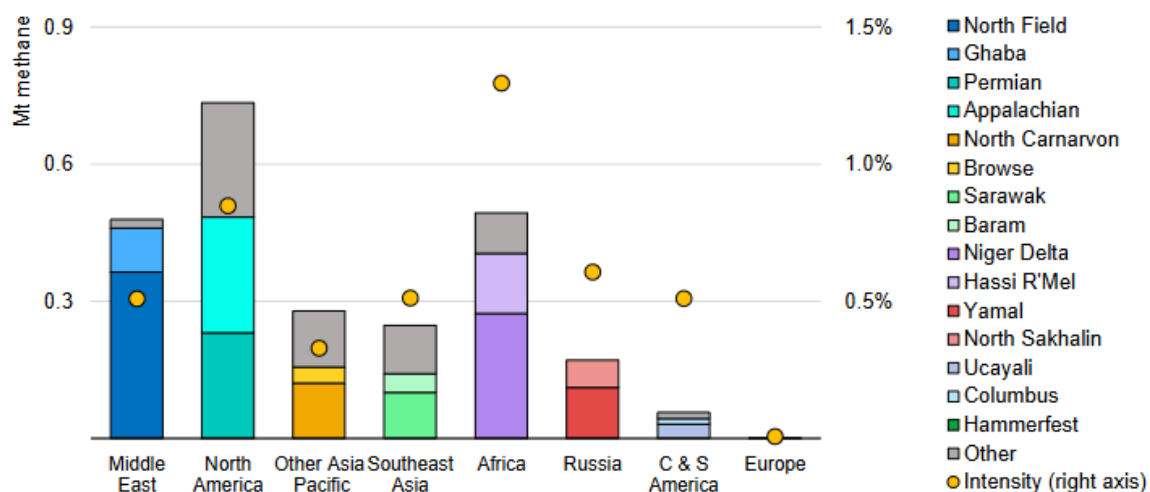
Another 2025 IEA study, assessing emissions from LNG supply, shows regional average upstream methane emissions in the natural gas supply in a range from near zero (Europe) to about 1.3% (Africa), as Figure 1 shows¹⁸. This report gives the global average emissions intensity of liquefied natural gas supply as 19.5 gCO₂eq/MJ, of which 14 gCO₂eq/MJ are emitted as CO₂ and the other 5.5 gCO₂eq/MJ as methane. "Production, processing and transmission" CO₂ is 34% of the CO₂ emission, i.e., 4.8 gCO₂eq/MJ, similar to the total DA CO₂ value, but excluding any transport emissions. The production, processing and transmission part of the average methane emission is equivalent to 0.73% leakage (excluding leakage in pipeline or other transport), slightly below the DA value of 0.88%.

¹⁶ The JEC Well-to-Wheel (WTW) version 5 database is a widely used reference compiled by the Joint Research Centre (JRC) of the European Commission and other EU experts. It provides standardised data on greenhouse gas emissions and energy use for different fuels and pathways, covering the entire life cycle from production ("well") to final use in vehicles or energy systems ("wheel"). Link: <https://publications.jrc.ec.europa.eu/repository/handle/JRC121213>.

¹⁷ IEA (2023), Emissions from Oil and Gas Operations in Net Zero Transitions.

¹⁸ IEA (2025), Assessing emissions from LNG supply and abatement options.

Figure 1: Regional average upstream methane emissions in the natural gas supply



Source: IEA (2025)

3.1.3. Deep dive methane intensity

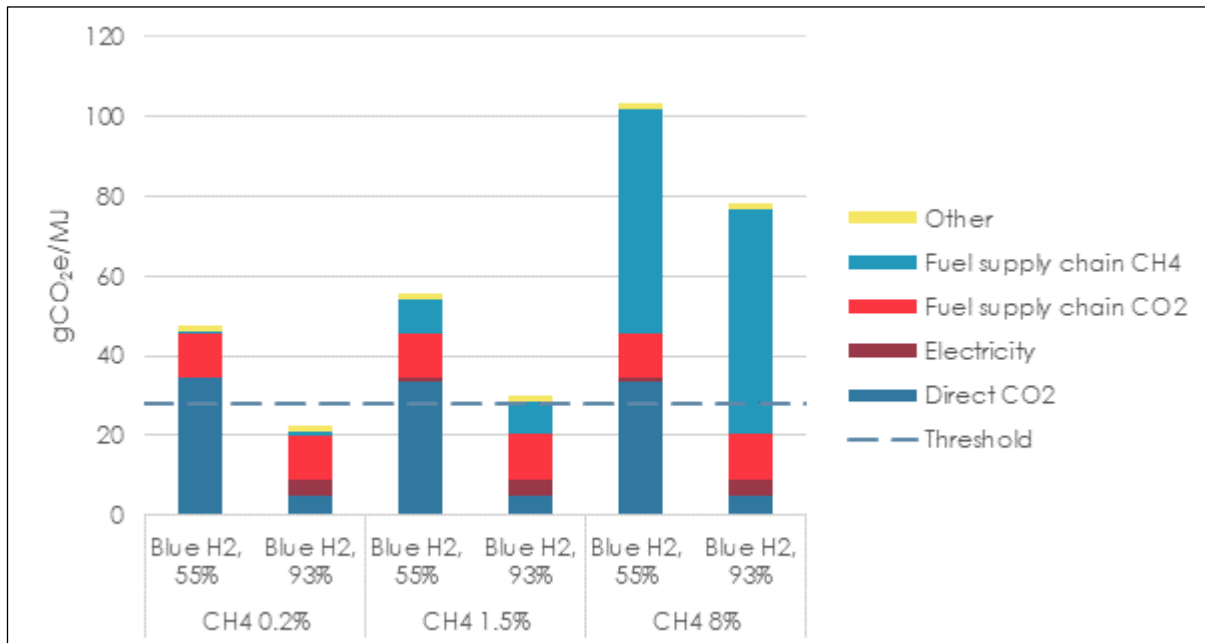
The production of natural gas, oil and coal is associated with the emission of methane to the atmosphere. This can be through a combination of routine methane venting, emergency methane venting, and fugitive emissions of methane from methane handling infrastructure, and can occur during fuel extraction, fuel processing and fuel transport. Methane is a strong greenhouse gas, with a global warming potential (GWP) 29.8 times higher per kilogram than that of CO₂ over a 100-year period according to the latest IPCC assessment. This means that per atom of carbon contained, methane is 11 times stronger as a greenhouse gas than CO₂. Note that the DA applies a GWP of 28 for methane following the older fifth IPCC assessment report. In contrast, the Methane Regulation references the most recent scientific assessment by the IPCC (Sixth Assessment Report) and prescribes to use the GWP of 29.8.

Given the high GWP of methane, the GHG intensity of produced fossil fuels is sensitive to the rate of methane leakage through the supply chain. The DA specifies default methane emissions of 0.190 g CH₄/MJ for natural gas, which is equivalent to an overall leakage of 0.88% by mass for the natural gas supply chain (excluding additional losses associated with LNG liquefaction, shipping and regasification). This translates into 5.6 gCO₂eq/MJ from methane leakage and 4.9 gCO₂/MJ from the production and transport-associated CO₂ emissions, excluding LNG. Crude oil and coal are associated with slightly higher methane defaults, 0.228 gCH₄/MJ and 0.39 gCH₄/MJ respectively.

For a blue hydrogen production efficiency of 76%, the default natural gas leakage rate of 0.190 gCH₄/MJ contributes about 7 gCO₂eq/MJ to the life cycle carbon intensity of blue hydrogen. Under these defaults, and assuming high process CO₂ capture rate (around 90%), blue hydrogen would qualify as an LCF under the DA. However, significantly higher methane leakage rates would make compliance impossible. For example, Bauer et al. (2022) report methane leakage rates up to 9% for one oil and gas formation (the Permian basin in the U.S.), which would add 71.6 gCO₂eq/MJ to the GHG intensity of blue hydrogen. This is based, however, on averaging across methane emissions from both oil and gas wells; because gas wells are always connected to gas handling infrastructure, losses from gas wells are

generally less than from oil wells. Figure 2 shows cases from Bauer et al. for the GHG intensity of blue hydrogen production under different assumptions on supply chain methane leakage and on capture rate¹⁹.

Figure 2: GHG intensity of blue hydrogen for different carbon capture rates and methane leakage rates (GWP 100)



Source: Bauer et al. (2022)

The DA requires operators to calculate the GHG intensity of low-carbon hydrogen production by accounting for both the actual carbon capture rate for blue hydrogen at the installation and the methane intensity of the fossil fuels used as inputs. The capture rate assumed for the calculation should reflect the installation's measured performance. The methane intensity, however, may either be set based on data reported under Regulation (EU) 2024/1787 on methane emissions in the energy sector, or by applying the DA's default value of 0.190 gCH₄/MJ (equivalent to 0.88% leakage by mass) as specified in Annex B.

a. Methane intensity data reporting

There are circumstances in which a low-carbon hydrogen producer may state that methane intensity data were not available for a batch of natural gas or other fuel. This "lack of data" is a recognised challenge, particularly for imported fossil fuels. The methane regulation (EU) 2024/1787 indicates the following contributing factors:

- There is currently limited accurate data, reported at the United Nations Framework Convention on Climate Change (UNFCCC) Tier 3 or using equivalent methods, on international methane emissions, so upstream methane intensity for imported fuels may be missing or unreliable.

¹⁹ Bauer, C. et al (2022)

- Many fossil energy exporting third countries have not yet submitted full inventory data to the UNFCCC secretariat. This means that the necessary upstream methane emission data for imported fuels might not be available or robust.

For natural gas production within the EU, the methane regulation creates clear responsibilities for producers to report methane emissions, and therefore it is reasonable to assume domestic methane intensity data will be available as the regulation is implemented: initial generic quantification by August 2025, and source-level quantification with specific emission factors, sampling or direct measurement, by February 2026. However, the picture for imports of fossil fuels is more complicated. A requirement is imposed on importers to report data or justify its absence, but the regulation does not define a universal penalty regime for failure to report, so penalties are set at Member State level and implementation remains uncertain. This creates a risk that methane intensity information for imports may be systematically unavailable in the near term, in which case default values from the DA would be applied. Concerns have been expressed about the implementation feasibility of the importer requirements and it is unclear when data reporting on imports will actually become normative²⁰.

When methane intensity data are reported under the methane regulation, the LCF producers still need to be able to identify the source of utilised fossil fuels in order to identify an associated methane intensity profile published by the European Commission²¹. However the DA is not clear regarding the responsibilities of an LCF producer purchasing batches of fossil fuels from intermediaries on the open market. The DA includes no explicit enforcement mechanism to ensure that LCF producers impose contractual obligations on their suppliers to share this data, which suggests the possibility that LCF producers continue relying on default values.

b. Implications of methane intensity for low-carbon hydrogen

It is possible to explore the implications for LCF of variation in methane intensity by calculating example life cycle emissions values for low-carbon hydrogen produced in gCO₂eq/MJ H₂ using natural gas from a range of different sources. Figures 3 and 4 combine the low-carbon hydrogen production GHG intensity assumptions from Bauer et al. (2022) with gas-field specific methane intensity values from the 'Oil Climate Index' for two fields each in Norway, the USA and Algeria²². Results are shown using both GWP over 100 years (consistent with EU regulatory accounting) and GWP over 20 years (to illustrate near-term climate impacts), given methane's high short-term warming potential²³.

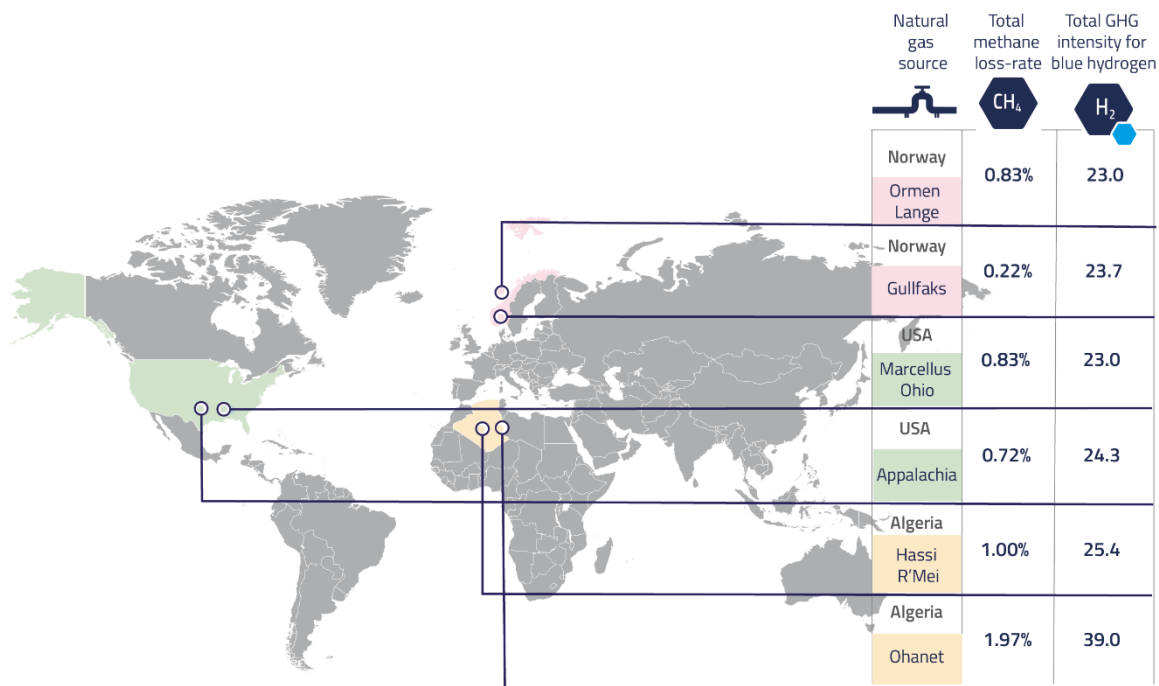
²⁰ E.g. the International Association of Oil & Gas Producers (IOGP), 2025, *Action plan to address key challenges on importers' requirements in the Methane Regulation*, <https://iogpeurope.org/resource/action-plan-to-address-key-challenges-on-importers-requirements-in-the-methane-regulation/>

²¹ The methane regulation requires the publication by the European Commission of 'methane performance profiles' that would include the methane emissions associated with fossil fuels placed on the Union market at both the national level and at the level of producers and of importers/exporters. For a known source of fossil fuels this should allow an LCF producer to identify a specific methane intensity (albeit potentially averaged over several individual fossil fuel sources)

²² Rocky Mountain Institute, 2023, *Oil Climate Index*, data queried on 24 August 2025, <https://ociplus.rmi.org/supply-chain>. Details about the method are provided in Annex 2 B1.

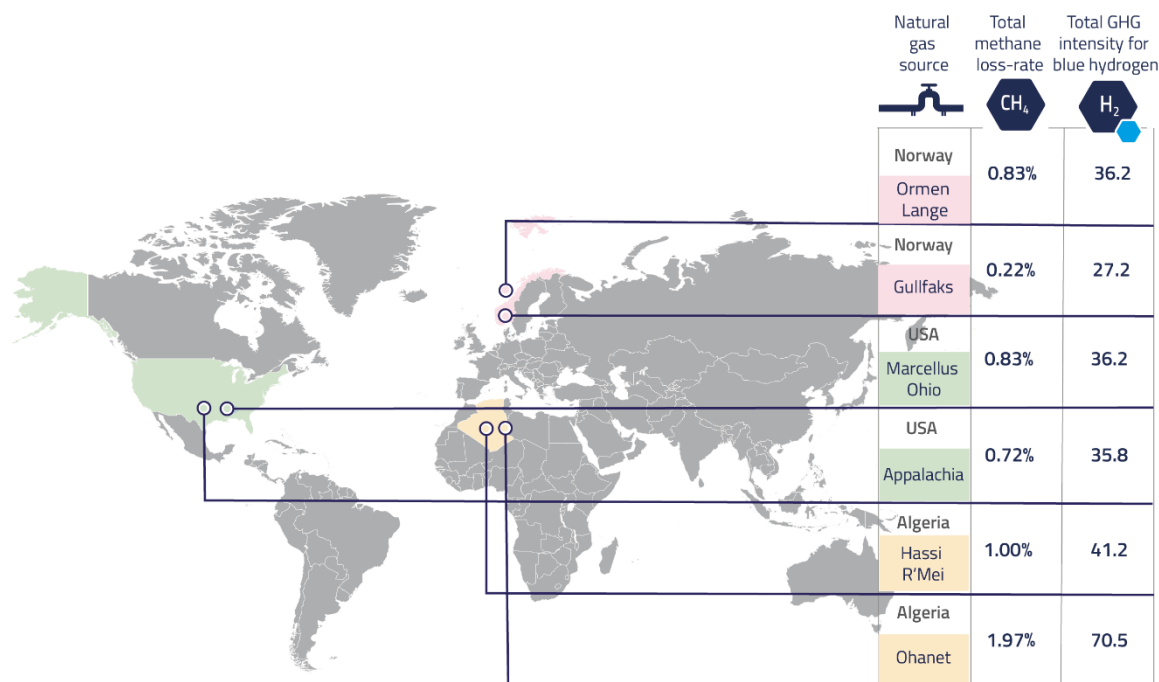
²³ Details about the GHG calculations can be found in Annex 2 B2.

Figure 3: Implied pathway GHG intensity (gCO₂eq/MJ H₂) for low-carbon hydrogen with 93% carbon capture from different gas sources (GWP100)



Source: FCA & Cerulogy extrapolation from Bauer et al. (2022) and OCI data using GWP 100

Figure 4: Implied pathway GHG intensity (gCO₂eq/MJ H₂) for low-carbon hydrogen with 93% carbon capture from different gas sources (GWP20)



Source: FCA & Cerulogy extrapolation from Bauer et al. (2022) and OCI data using GWP 20

Four of the exemplar fields (the Norwegian and U.S. cases) have methane leakage rates that are lower than the DA default value. The examples chosen are not unusually methane-efficient. In fact, Ormen Lange has the highest methane losses of the Norwegian gas fields documented by the OCI, and Marcellus Ohio the highest methane losses of the U.S. fields. The Ohanet field in Algeria, however, has a reported leakage rate of 1.97%, which is high enough that the resultant hydrogen GHG intensity would be about 39 gCO₂eq/MJ. While Bauer et al. (2022) included a case for 8% methane leakage, this rate of leakage would be very unusual for a gas field: the highest loss rate documented for any field in the world in the OCI data is 5.2%. Bauer refers to a leakage rate across the U.S. Permian shale of 9%, but this reflects losses from both gas fields and oil fields; some oil fields have very high rates of gas loss due to having no gas collection infrastructure, and therefore leakage rates that include oil-only fields are not representative of the gas industry. In summary, the leakage rate of 0.88% used to calculate the default value is justifiable. An argument could be made, however, that the default value in the DA ought to be more conservative in order to provide an incentive for actual value reporting – the current default provides a potential route for LCF produced with natural gas from higher carbon-intensity fields to achieve compliance with the threshold that does not reflect real performance, using the lower default value. While concerns about potential underreporting of methane emissions are legitimate, the very high emission rate figures often cited typically result from combining oil and gas operations.

3.1.4. LNG liquefaction and transportation

As the previous chapter indicated, LNG typically has a significantly higher emissions intensity than natural gas supplied without liquefaction directly via pipeline. This is primarily due to the energy required for liquefaction, but also to methane losses during transport and transfer.

The DA states that the default emissions intensities for natural gas as an input do not include emissions associated with liquefaction and transport of LNG, but the DA provides only limited guidance on how these emissions should be characterised when actual data are unavailable. The footnotes to Table 1 in Part B of the annex point back to paragraph 7 of section A of the annex and to the methane regulation but no standardised default methodology is defined.²⁴

FCA's understanding is that the methane regulation requires natural gas importers, including LNG, to report value chain emissions from August 2028, using a methodology the Commission will publish by August 2027. This methodology will define how LNG emissions are calculated and thus shape the rules for low-carbon hydrogen producers. Until then, reporting relies on estimated data and literature, but in the absence of a standardised approach, this creates uncertainty and a risk of underreporting. This puts the responsibility on competent authorities and third-party verifiers to make a decision about how these emissions may be characterised.

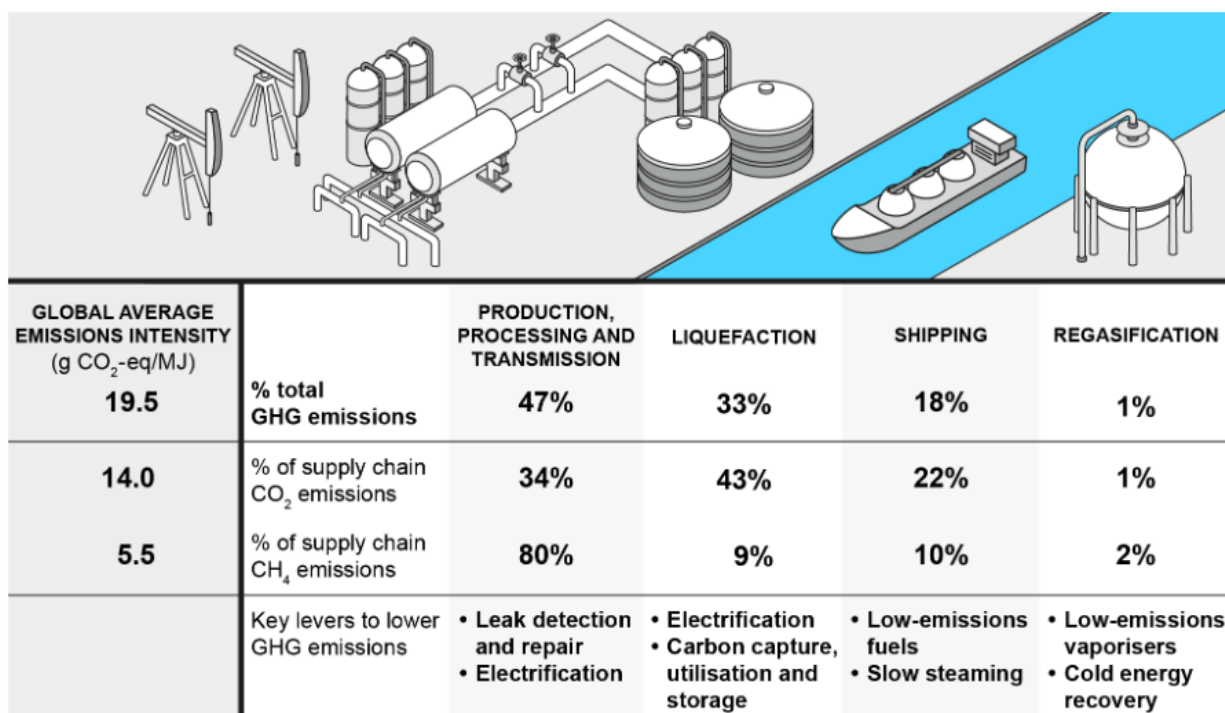
Some literature estimates exist. One potential source for default values would be the JEC Well to Wheels study which suggests about 5 gCO₂eq/MJ for liquefying natural gas, and an additional 3.5 gCO₂eq/MJ associated with transporting LNG by sea over an assumed distance of 4000 nautical miles (implying 11 gCO₂eq/ MJ H₂, though this would be partly offset by avoided pipeline emissions). This is not a negligible contribution, and is about double the overall JEC Well to Wheels estimate of emissions for natural gas supplied by pipeline. If another source is taken, the IEA report on emissions in the LNG supply chain in June 2025 shows a total average emissions from LNG at 19.5 gCO₂eq/MJ, compared to 12 gCO₂eq/MJ from natural gas via pipeline, with energy for liquefaction accounting for about 6 gCO₂eq/MJ, shipping for about 3.5 gCO₂eq/MJ (similar to the JEC estimates) and regasification being about 1.5 gCO₂eq/MJ, as shown in Figure 5.²⁵

For some low-carbon hydrogen systems, LNG emissions could be enough to make the difference between meeting and missing the threshold, and thus, clarity on how they should be assessed is needed.

²⁴ Annex Part B Table 1: "(**) for natural gas that was transported in liquid form additional GHG emissions (CO₂, CH₄ and N₂O) due to liquefaction, shipping and regasification of natural gas shall be added."

²⁵ IEA (2025), Assessing emissions from LNG supply and abatement options

Figure 5: Global average emissions from LNG supply by part of the supply chain



Source: IEA (2025)

3.2. Electrolytic pathway

3.2.1. Overview of electricity emissions factor accounting options

In the case of hydrogen generated via electrolysis, produced by splitting water using electricity, electricity is the major source of indirect GHG emissions. The GHG intensity of electricity consumed by electrolyzers is determined following rules similar to those applied under the DA on life cycle accounting for RFNBOs produced together with RCFs with an additional fourth accounting option.

The GHG intensity of electrolytic hydrogen is equal to the GHG intensity of the input electricity divided by the energy efficiency of the conversion plus any additional emissions incurred in the production process. However, the main difference is that the GHG intensity of RFNBO-eligible electricity is counted with 0 gCO₂eq/MJ, effectively giving renewable hydrogen a zero-emission footprint for accounting purposes.

The choice of electricity source is therefore the key determinant of whether electrolytic hydrogen is considered low-carbon or zero-carbon under EU rules, unlike hydrogen from natural gas, where upstream methane leaks, and liquefaction and transportation also matter.

The rules for LCF allow the GHG intensity of consumed electricity to be established on one of four bases:

1. Option 1: Based on yearly averages across electricity generation calculated at the level of countries or bidding zones, adjusted for imports and exports²⁶;
2. Option 2: Based on the forecasted carbon intensity of the hourly electricity mix in the bidding zone at the time of production of the low carbon fuels (added for LCFs);
3. Option 3: As zero if the number of full load hours for which the facility operates is less than the number of load hours during which the marginal price of electricity was set by renewable power plants or by nuclear power plants in the preceding year;
4. Option 4: As an hourly average based on the GHG emissions of the marginal technology setting the clearing price of electricity in the bidding zone at the time of plant operation, if available.

It is important to distinguish between the calculation of GHG emissions from RFNBO and LCF hydrogen, and the determination of the share of RFNBO and LCF in the final hydrogen output.

For GHG emissions accounting, electricity used in an electrolyser that is sourced in full compliance with the RFNBO criteria set out in Directive (EU) 2018/2001 and Delegated Regulation (EU) 2023/1184 is counted as having 0 gCO₂eq/MJ. Electricity that does not meet these criteria must be assigned an emissions factor in accordance with the relevant LCF rules.

By contrast, the calculation of the RFNBO and LCF shares in the final hydrogen output applies a broader methodology. All electricity sourced in line with Delegated Regulation (EU) 2023/1184 is fully counted as RFNBO, while a proportional share of renewable energy in the grid mix can also be attributed to RFNBO hydrogen even if the electricity used does not strictly meet RFNBO criteria. This approach is set out in Delegated Regulation (EU) 2023/1185.

Two scenarios are elaborated below. Section 3.2.2 examines which power sources meet the LCF standard independently, while Section 3.2.3 explores the integration of dedicated RFNBO-Eligible Electricity Sourcing.

3.2.2. Non-renewable power sources and grid sourcing

Hydrogen produced from renewable energy is eligible to be counted as an RFNBO, with an electricity GHG intensity of 0 gCO₂eq/MJ. Compared to RFNBOs, one of the key differences in GHG accounting for LCFs is the possibility of producing this fuel type using, for example, nuclear power or fossil power with carbon capture. As an illustrative benchmark, we can note that the exclusive use of electricity with a GHG intensity of 20 gCO₂eq/MJ for LCF production would usually result in a GHG value that is just above the proposed threshold²⁷.

Nuclear power is presumed in the DA to be produced from nuclear heat at an efficiency of 33% (unless a different efficiency can be established). Nuclear heat is assigned an input GHG intensity of 0.5

²⁶ Most bidding zones in the EU still correspond to national borders, and some countries are joined into a single bidding zone (e.g. Germany and Luxembourg), but some contain several bidding zones (e.g. Italy).

²⁷ Assuming production without any RFNBO-eligible electricity and assuming an electrolyser with an efficiency of 70%. This number is used throughout the report if not otherwise specified and is chosen based on the U.S. Department of Energy's alkaline electrolyser efficiency targets for 2026, <https://www.energy.gov/eere/fuelcells/technical-targets-liquid-alkaline-electrolysis>

gCO₂eq/MJ, implying an electricity GHG intensity of 1.5 gCO₂eq/MJ. This puts hydrogen produced from 100% nuclear electricity well within the implied threshold with a GHG intensity of 2.2 gCO₂eq/MJ H₂.

Meeting the threshold solely with natural gas-based electricity, on the other hand, would be almost impossible, even with a very high rate of carbon capture. Taking natural gas as an input to a gas turbine achieving 60% electrical generation efficiency with a carbon capture unit, the upstream GHG intensity of the natural gas supply would come to 17 gCO₂eq/MJ electricity. Combustion emissions from this system would therefore need to be kept below 3 gCO₂eq/MJ to stay within the threshold, implying a carbon capture rate of 97% (technically unachievable for a power plant). Therefore, achieving low-carbon hydrogen with natural gas-based electricity is almost impossible, even with high CCS performance.

Even though grids already include some RFNBO-eligible electricity, using the yearly average grid emission intensities from DA Annex Table 5 and calculating emission intensities for specific Member State grids reveals that, in some countries, relying solely on grid electricity will not be sufficient to meet the threshold. In such cases, a mixed scenario sourcing RFNBO-eligible electricity via Power Purchase Agreements (PPAs) or direct renewable generation will be necessary to ensure compliance.

Table 2: GHG intensity for LCF hydrogen from non-renewable sources and grid sourcing

| Electricity source | Assumed electrolyser efficiency | GHG intensity of electricity (gCO ₂ eq/MJ) | GHG intensity of produced H ₂ (gCO ₂ eq/MJ) |
|--|---------------------------------|---|---|
| Nuclear power only | 70% | 1.5 | 2.2 |
| Natural gas Combined Cycle Gas Turbine (CCGT), 60% efficient with 85% CC | 70% | 31.2 | 46.2 |
| Coal, 30% efficient with 85% CC | 70% | 106.8 | 158.3 |
| France grid | 70% | 15.4 | 22.8 |
| Sweden grid | 70% | 3.4 | 5.0 |
| Poland grid | 70% | 174.8 | 258.8 |
| Germany grid | 70% | 103.8 | 153.7 |

Source: FCA & Cerulogy analysis, DA Annex Part B Table 5.

3.2.3. Integration of dedicated RFNBO-Eligible Electricity Sourcing

The assessment of the GHG intensity of electricity for LCFs is based on either the instantaneous electricity mix (options 2 or 4 mentioned above) or the annual average electricity mix (options 1 or 3). Given that all EU grids contain some renewable electricity production at most hours, electrolytic hydrogen is almost always produced from a mixed electricity supply. Thus, multiple combinations of RFNBO-eligible and non-RFNBO-eligible production scenarios are possible, based on the fraction of a project's electricity input covered by grid electricity vs. the different RFNBO-eligible electricity sourcing options: direct connection to renewable electricity, grid electricity sourcing in countries with renewable energy share >90%, and grid GHG intensity below 18 gCO₂eq/MJ, combined with the sourcing criteria of additionality, temporal correlation, and geographical correlation.

For example, based on 2023 data from the DA Annex table 5, there are five countries in which the average electricity GHG intensity was below the implied²⁸ 20 gCO₂eq/MJ threshold: Sweden, Finland, France, Denmark and Lithuania. According to Green Grid Compass²⁹, of these, Sweden (in particular the southern bidding zones), Finland, and France had significant contributions from nuclear power. None of these countries has eliminated non-renewable power yet, and therefore hydrogen produced by electrolysis in these countries using the grid average accounting option would be part RFNBO, part LCF, reflecting the mixed electricity supply.

For countries still with a significant contribution from fossil power, because the RFNBO and LCF hydrogen are assigned the same carbon intensity value, one could argue that the LCF fraction inherits the low GHG intensity of renewable power despite not being identified as renewable (as if only the fossil generation is considered, the LCF would not meet the threshold requirement). Looking at the examples of Germany and Poland, two grids with a high share of fossil-electricity generation, producing LCF would only be possible with a high proportion of RFNBO-eligible renewable electricity sourced, for example, through a PPA to meet the threshold.

Over time, given that the renewable share in the grid is increasing across Europe, and therefore the average GHG intensity is reducing across the EU, the number of countries or bidding zones in which all electrolysis hydrogen could count as LCF will continue to increase with time. Therefore, countries with low-carbon grids or that can access RFNBO-eligible imported electricity can produce low-carbon hydrogen more easily, while high-fossil grids require dedicated renewable sourcing.

3.2.4. Indirect emissions for LCF production

If there is a significant growth in the production of electrolytic LCF, this would imply increased electricity demand on the grid. If this demand cannot be met by increased utilisation of existing plants, it must be met either by installing new power capacity or by extending the life or increasing the utilisation of existing capacity. This issue of indirect emissions is not unique to LCFs and is ameliorated by the parallel action of the Emission Trading Scheme (ETS) and other policies to reduce the GHG intensity of power more generally.

²⁸ As previously indicated, for an electrolyser with an efficiency of 70%.

²⁹ Green Grid Compass, 2025, <https://www.greengrid-compass.eu/>.

For price-responsive electrolyzers, the indirect effects of additional demand for electrolysis depend on the effective market price of low-carbon hydrogen. This price will be set by policy-based incentives, for example creating demand or giving price guarantees. There will only be an incentive to produce low-carbon hydrogen if the electricity to do so costs less than the hydrogen price. Under normal circumstances, producing LCF with fossil electricity will only be incentivised if the low-carbon hydrogen price is above the marginal cost of electricity from fossil generation. This cost is usually significantly above the marginal cost of nuclear and renewable production³⁰. In other words, producing hydrogen with fossil electricity would be too expensive compared to nuclear or renewables if production incentives are moderate. Electrolyzers will preferentially consume low-cost (i.e., mostly low-carbon) electricity first, responding to prices and thus reducing the risk of indirect emissions with additional fossil generation.

³⁰ The inflexible nature of some fossil power plants as well as regulatory circumstances can force operators to continue producing power despite prices falling below the marginal cost of production. If they were to stop production, they could not profit from providing ancillary grid services and would lose opportunities for revenue generation after the low-price period, as they cannot ramp up generation fast enough after having reduced their output. Effectively, this means they are willing to pay consumers to take their electricity output, i.e. the marginal price for fossil electricity at such times is negative. Support schemes for renewables can protect them from such effects, meaning their effective marginal cost of production is always lower, i.e., even more negative. Under such conditions, any electricity demand of any kind will benefit fossil electricity production in the sense that it reduces the economic pressures of negative prices on fossil production. To the degree that these pressures promote the phasing out of inflexible fossil plants, reducing it may slow down this process. The effect of demand from electrolyzers would be proportionate to its share in total demand though, i.e., likely a small fraction in the near-term.

4. DELEGATED ACT IMPACT ON HYDROGEN PRODUCTION COSTS

KEY FINDINGS

Complying with LCF standards increases cost compared to conventional unabated hydrogen production. This is due to the need for additional equipment for carbon abatement processes (CCS or CCU) or restrictions of electrolytic production to low GHG intensity hours.

Regarding blue hydrogen (i.e., hydrogen produced from natural gas with CCS), costs are higher than unabated fossil hydrogen costs (i.e., grey hydrogen). There is little variation in cost between Member States since the natural gas feedstock cost constitutes the largest share of expenditure. CO₂ transport and storage costs remain a significant uncertainty factor and require relatively large scales to achieve low values.

The cost of blue hydrogen is estimated to be in the range of 3.5–6.5 €/kg, with a likely value of around 5 €/kg. This represents a roughly 45% premium over grey hydrogen, which can be produced at a cost of 2.2–4.9 €/kg using the same modelling assumptions as for blue hydrogen. However, it is unlikely that new unabated SMR plants will be built in the EU, and most existing grey hydrogen facilities will have already amortised their capital costs. Despite this, blue hydrogen costs are mostly determined by natural gas prices rather than plant costs, so the uncertainty of future gas prices is more significant.

Electrolytic low-carbon hydrogen costs are at present higher than those of blue hydrogen but lower than RFNBO hydrogen. Cost reductions of electrolyzers are allowing more selective consumption of low-cost electricity due to reduced need for high asset utilisation rates. While electrolyser costs are decreasing, the speed of progress is a significant uncertainty factor. Low electricity prices are correlated with low emissions in most bidding zones. Therefore, in the future, more selective low-cost electrolyzers will be less restricted by DA thresholds.

Low-carbon electrolytic hydrogen prices calculated for this study range from 2.73 €/kg applying learning-curve based future CAPEX cost to 5.84 €/kg for higher electrolyzers CAPEX (actual current costs). However, electricity will remain the main contributor to the cost of hydrogen, at approximately 50%, or more when grid costs are high.

In high to medium GHG intensity grids, electrolyzers being restricted from producing low-carbon hydrogen in certain hours would lower the capacity factor below the economic optimum, increasing costs. In such cases, renewable PPAs will be necessary to cover part of the electricity supply and bring down average GHG intensity. This increases average electricity cost but increases RFNBO hydrogen production.

4.1. Overview of cost analysis

As indicated in Chapter 1 (Key Elements of the Delegated Act), the DA is technology-open and does not prescribe specific production pathways. The main criterion is that LCFs achieve at least a 70% reduction in GHG emissions relative to the unabated fossil reference. In practice, this carbon intensity threshold restricts the range of allowable production pathways for LCFs, as some exceed this limit. Since hydrogen is the key element in most scalable fuel production pathways (i.e., hydrocarbon-based LCFs) as well as a fuel in its own right, this chapter focuses specifically on the current and potential future cost of two types of hydrogen production pathways: (i) natural gas-based hydrogen production with CCS (blue hydrogen) and (ii) electrolytic hydrogen production from grid electricity. We note that coal-based pathways are excluded as they currently are not likely to be able to meet the emissions intensity threshold at achievable carbon capture rates.

Meeting LCF requirements generally increases costs compared to the purely cost-optimised version for a given production pathway. For blue hydrogen pathways, the increase is mainly due to the addition of carbon capture and storage on top of the conventional equipment used for grey hydrogen production. For electrolytic pathways, costs are already higher than for grey hydrogen and may rise further if hydrogen production is restricted during periods of emissions-intensive electricity generation, when electricity prices at those times would otherwise favour cost-minimised production.

A common metric for comparing the costs of different pathways is the levelised cost of hydrogen (LCOH). The LCOH definition used for the purpose of this analysis³¹ is the annual fixed and variable costs of the hydrogen production facility divided by the total hydrogen produced, and is given by,

$$\text{LCOH} = \frac{\text{Total annual costs}}{\text{Annual hydrogen production}} = \frac{\text{annuitized CAPEX} + \text{fixed OPEX} + \text{variable OPEX}}{\text{Plant capacity} * \text{capacity factor}}$$

where total costs comprise the annuitized capital expenditure (CAPEX) and operating expenditure (OPEX). Variable OPEX covers system inputs such as fuel inputs and electricity, while fixed OPEX covers recurring constant costs such as operation and maintenance of the facility. The detailed methodology for calculating these costs is provided in Annex 1 of this report.

The scope of this cost analysis comprises the most relevant technical aspects but excludes taxes, levies, fees, and other charges, except for grid costs. For ease of relative comparisons, this is also applied to the grey hydrogen benchmark cost calculation. The analysis also excludes hydrogen transport and storage costs, both within the Union and for hydrogen import routes.

4.2. Cost of natural gas pathways

The most common method of hydrogen production is steam methane reforming (SMR). In this process, methane and steam (i.e. water) undergo a chemical reaction to produce hydrogen and carbon dioxide. Low-carbon, natural gas-based hydrogen production pathways use the same process but additionally integrate a CCS system to capture the carbon dioxide for long-term storage or utilisation.

³¹ The methodology to calculate the LCOH is based on the approach by the National Renewable Energy Laboratory (Aldersey-Williams et al., 2019).

In this section, we compare the costs of hydrogen production from the most established blue hydrogen pathway, steam methane reforming (SMR) with CCS. We also consider a less common alternative, autothermal reforming (ATR), which is well suited to CCS. Note that ATR combines steam reforming with an additional heat-producing chemical reaction, which avoids the need for fuel combustion to supply heat. This eliminates the associated low-concentration CO₂ stream and enables higher capture rates compared to SMR. ATR systems commonly include additional processing equipment, and this is reflected in the cost analysis presented in this paper.

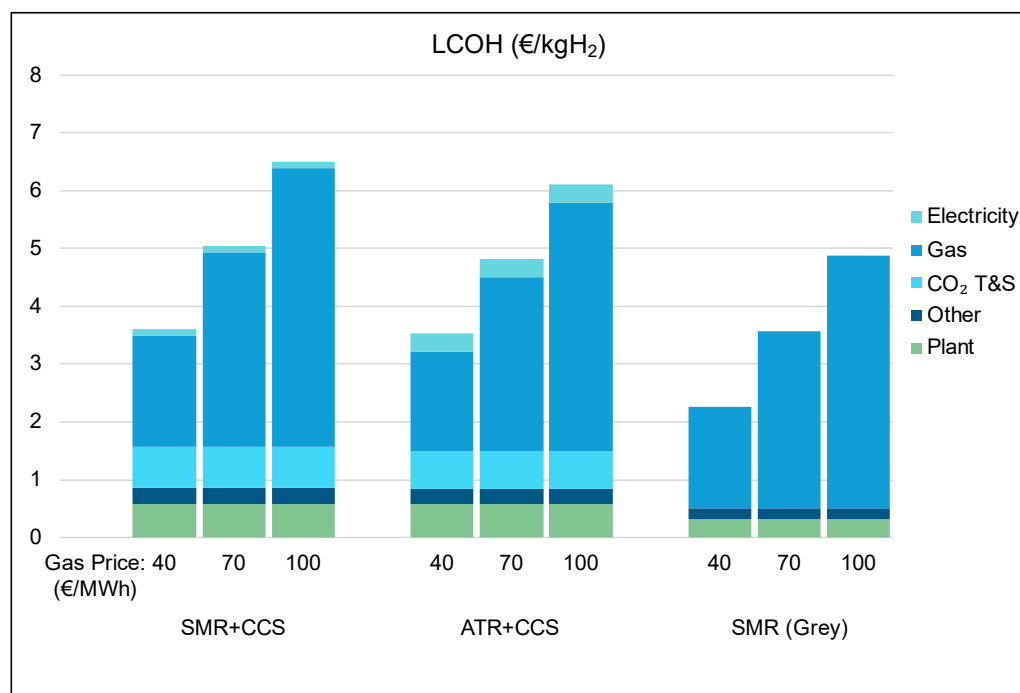
SMR+CCS and ATR+CCS are regarded as the most likely LCF systems to be deployed at scale in the near term, due to their lower costs relative to other low-carbon hydrogen pathways. For the remainder of this section, their costs are compared with conventional SMR without CCS (also referred to as grey hydrogen).

We note that for both reforming technologies with CCS, costs are not strongly determined by the LCF emissions threshold, as most systems remain within the limit provided that upstream natural gas supply has low methane leakage. In other words, as long as the capture rate is high enough and the overall emissions remain below the threshold, the CCS requirements do not change. In this analysis, we assume no price premium for low-leakage natural gas.

4.2.1. Impact of natural gas price

Figure 6 shows the LCOH for the main natural gas-based hydrogen production pathways, alongside a grey hydrogen benchmark. In each bar, the LCOH is categorised into the main cost components. For each pathway, the natural gas price is varied between 40 €/MWh, 70 €/MWh, and 100 €/MWh, to represent different cost scenarios. A price of 40 €/MWh is representative of the average price since the start of 2025, while 70 €/MWh corresponds to the average since February 2022, following the onset of the war in Ukraine. The 100 €/MWh scenario is representative of the average between February 2022 and February 2023, the most volatile period during the conflict.

Figure 6: Levelised cost of hydrogen for varying gas prices



Source: FCA analysis.

Note: Underlying sources provided in Tables 3-5 of Annex 1. LCOH = Levelised cost of hydrogen; SMR = Steam methane reforming; ATR = Autothermal reforming; CCS = Carbon capture and storage. Grey refers to an SMR system without CCS.

The cost of blue hydrogen is estimated to be in the range of 3.5–6.5 €/kg. The lower end of this range reflects production costs for current gas prices of 40 €/MWh. This corresponds to a roughly 60% premium over grey hydrogen, which can be produced at a cost of 2.2–4.9 €/kg using the same modelling assumptions. However, it is unlikely that new unabated SMR plants will be built in the EU, and most existing grey hydrogen facilities will have already amortised their capital costs. As a result, their production costs are driven only by fuel and operating expenses (unlike new projects that must also include CAPEX) resulting in an LCOH of approximately 1.7–4.4 €/kg. At current gas prices, this leads to a premium of 100% for hydrogen produced by new build plants with CCS.

A key takeaway from this analysis is that the natural gas feedstock cost is the dominant driver of blue hydrogen production costs. For the price scenario of 40 €/MWh, natural gas is approximately 55% of the total LCOH. As gas prices increase, the LCOH rises accordingly. For every 1 €/MWh increase in the natural gas price, the LCOH increases by about 0.05 €/kg; a trend that applies equally across all production methods, whether or not CCS is included.

4.2.2. Impact of plant and equipment cost

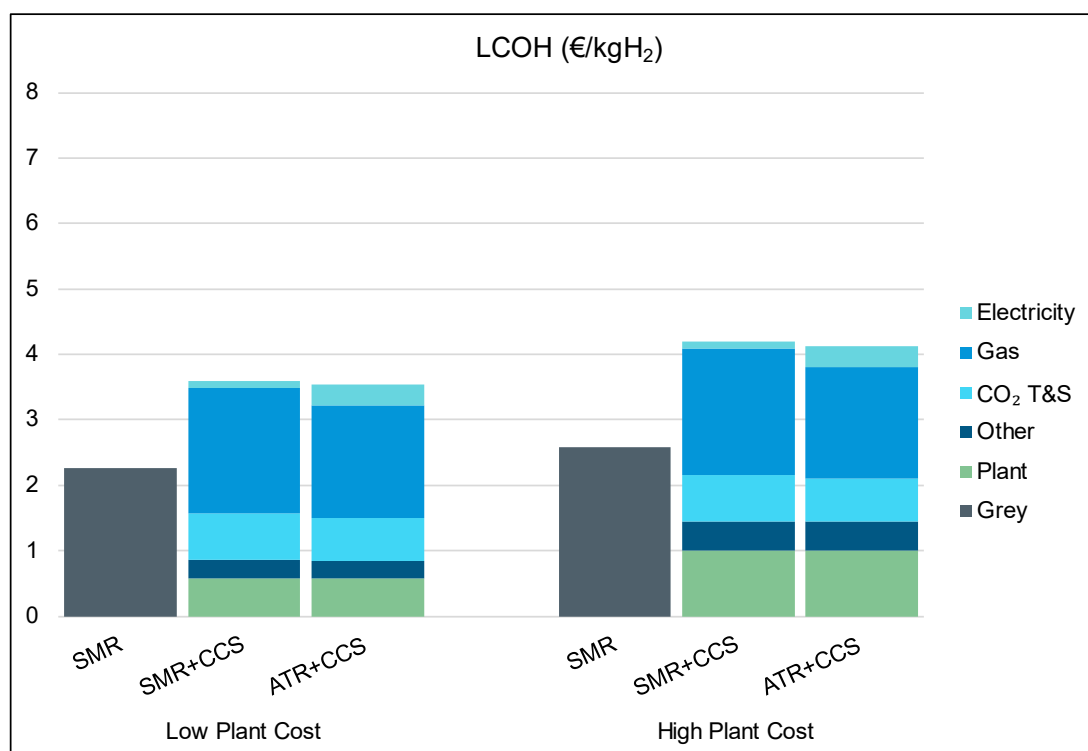
The capital costs of the reforming plant and the CCS system are also significant contributors to the LCOH. For both SMR and ATR, the reforming section accounts for 50–60% of total CAPEX, while the CCS system accounts for 40–50% (i.e. the inclusion of CCS increases total capital expenditure by about 80%). In general, the CAPEX of SMR+CCS and ATR+CCS plants is close in cost. The higher gas

consumption of SMR (due to additional heating requirements) is offset by the higher electricity demand of the ATR. For comparison, the benchmark grey hydrogen pathway (SMR without CCS) is cheaper because it avoids the additional 80% in plant CAPEX associated with CCS, as well as the costs of CO₂ transport, storage, and additional electricity consumption.

Figure 7 shows the impact of plant CAPEX on the LCOH, assuming a natural gas price of 40 €/MWh. The left side of the figure represents a “low-cost plant” with a CAPEX of 1,300 €/kW_{H₂}, while the right side shows a “high-cost plant” with a CAPEX of 2,600 €/kW_{H₂}. The low CAPEX values are based on values reported in the research literature, institutional reports, and consultations, while high values are drawn from actual current projects and industry news (See Annex A for detailed sources). For scale, the total investment cost of a large blue hydrogen plant is typically in the low billions of euros.

However, a 70% increase in plant CAPEX results in only a 15-20% increase in the LCOH. This, again, reflects the dominance of lifetime gas costs over capital investment, with LCOH far more sensitive to natural gas prices. CCS increases upfront investment, but its relative impact on LCOH is smaller.

Figure 7: Levelised cost of hydrogen for selected pathways



Source: FCA analysis.

Note: Underlying data provided in Tables 3-5 of Annex 1. Calculated assuming a gas price of 40 €/MWh.

4.2.3. Impact of CO₂ transport and storage cost

Transport and Storage (T&S) of the captured CO₂ is also a significant cost component, accounting for approximately 20% of the total LCOH, in the 40 €/MWh gas price scenario. This is comparable in magnitude to the total CAPEX of the plant. For every 1 kg of hydrogen produced, around 8-9 kg of CO₂ must be managed. In this analysis, a cost of €80 per tonne of CO₂ is assumed, based on the large-scale

and long-life infrastructure required. In practice, costs will depend on infrastructure sizing and utilisation rates, with the first movers likely facing higher costs due to the low initial utilisation.

Estimates of T&S costs vary considerably in the literature, with older studies and integrated assessment models typically applying lower values. We adopt a higher figure, consistent with recent literature suggesting that T&S costs have been typically under-estimated³². T&S costs in Europe, in particular, are expected to exceed global averages due to the greater reliance on shipping rather than pipelines. For context, the assumed €80 per tonne of CO₂ is lower than the estimated €100 per tonne reported for the Aramis project in the Netherlands³³.

4.2.4. Variation by country

The cost of blue hydrogen production is unlikely to vary significantly across European Member States, as natural gas prices are largely indexed to the Dutch TTF benchmark³⁴. While gas grid connection costs do differ between countries, their contribution to overall LCOH is minor, adding only around 0.08 €/kg.

4.2.5. Retrofitting existing SMR facilities

SMR plants currently account for around 75% of global hydrogen production (according to the IEA's 2019 *Future of Hydrogen* report). As a result, there is significant interest in retrofitting existing SMR facilities with CCS to make use of existing capital, while reducing emissions.

Achieving the capture rates required to qualify as LCF hydrogen will be challenging for retrofit projects, since these plants were not originally designed for the integration of a CCS system. This will likely result in lower capture efficiency, shorter operating life, and higher cost³⁵. Experience from retrofit projects in Texas and Canada shows capture rates of 50–60%, as only process-related CO₂ is captured, while flue gas emissions from heating are not³⁶. Extending capture to the flue gas stream to reach a capture rate of 90% is technically feasible but likely cost-prohibitive, and higher than new-build SMR/ATR plants designed with CCS. A further limitation is site layout, as CCS equipment can substantially increase the footprint of a facility, often requiring 30–50% additional land³⁷.

Note, however, that many European SMR plants are aging, meaning the most cost-effective initial GHG savings are likely to come from upgrading or replacing the reforming components.

4.3. Cost of electrolytic pathways

Hydrogen production with electrolysis means splitting of water into hydrogen and oxygen with electricity. All the energy in the hydrogen produced stems from the electricity input. There are several variants of this technology, but the general principle is very similar between variants. This cost analysis

³² Research article by Smith *et al.* covering the cost of transport and storage of CO₂ in integrated assessment modelling (2019).

³³ More details on European CO₂ T&S costs can be found in CATF's 2025 report on *Building Future-Proof CO₂ Transport Infrastructure in Europe*.

³⁴ Correlation to Dutch TTF shown by Hulshof *et al.* 2016.

³⁵ These challenges are similar to those observed in CCS retrofits on power plants, as discussed in a 2011 report by the IEAGHG.

³⁶ Performance of CCS retrofits discussed by CATF in 2021 report.

³⁷ HFI Energy Systems (2024)

assumes a so-called proton exchange membrane electrolyser (PEM) but is broadly applicable to most forms of electrolysis³⁸; detailed assumptions can be found in the Annex.

While the concept of electrolysis has been known and used for a long time, the use at industrial scale is still under development. As of 2024, 0.385 GW of electrolysis capacity was installed in the EU, while 2.6 GW of capacity had reached final investment decisions³⁹. Compared to blue hydrogen pathways, it is less mature and development across the variant technologies is more active; plant and equipment costs are still decreasing⁴⁰.

Another difference of the electrolytic pathway compared to blue hydrogen pathways is that FCA's cost analysis indicates a much more heterogeneous landscape across Member States with different grid GHG intensity profiles. The DA puts very different restrictions on the use of electricity to produce low-carbon hydrogen in different bidding zones, so it has more complex implications for costs.

Finally, electricity prices vary on an hourly timescale, much shorter than the slower variations in gas prices. This increasingly allows minimising total costs by operating electrolysers flexibly instead of year-round⁴¹. Because of this, the operational dispatch strategy is a key variable in the LCOH analysis of electrolytic hydrogen in the future.

In the following, we will present case studies for the bidding zones of France, Spain, and Germany.

4.3.1. Impact of plant and electricity cost on electrolytic hydrogen production

Figure 8 shows the LCOH for the electrolytic hydrogen production pathway for the example of France, which has an annual average grid GHG intensity sufficiently below the LCF threshold of 28.2 gCO₂/MJ. This value permits year-round production of low-carbon hydrogen with grid electricity based on methodology (a) in the DA annex. The costs are shown alongside a grey hydrogen benchmark. In each bar, the LCOH is categorised into the main cost components. We show three scenarios for capital costs and matching operational strategies, which in turn affect the achievable average electricity cost (see Annex for details on the methodology). The scenarios cover 2024 plant costs, near-term projections roughly for 2030, and averaged medium-term projections to 2035, to give a representative view of the range found in literature⁴². Note however, that the uncertainty in the trajectory of plant costs is large, even on current costs, which is made all the more relevant by their strong effect on LCOH. This will be discussed briefly at the end of this chapter.

³⁸ Costs are influenced by flexible operation, for which PEM is generally taken to be more suitable. At present it also tends to have slightly higher capital costs compared to other technologies. However, these differences are negligible compared to the uncertainty in future cost trajectories and even compared to prices quoted across different markets today (Gong 2025). Experience curve projections also predict a convergence of costs for different technologies, albeit with high uncertainty (Bühler 2024).

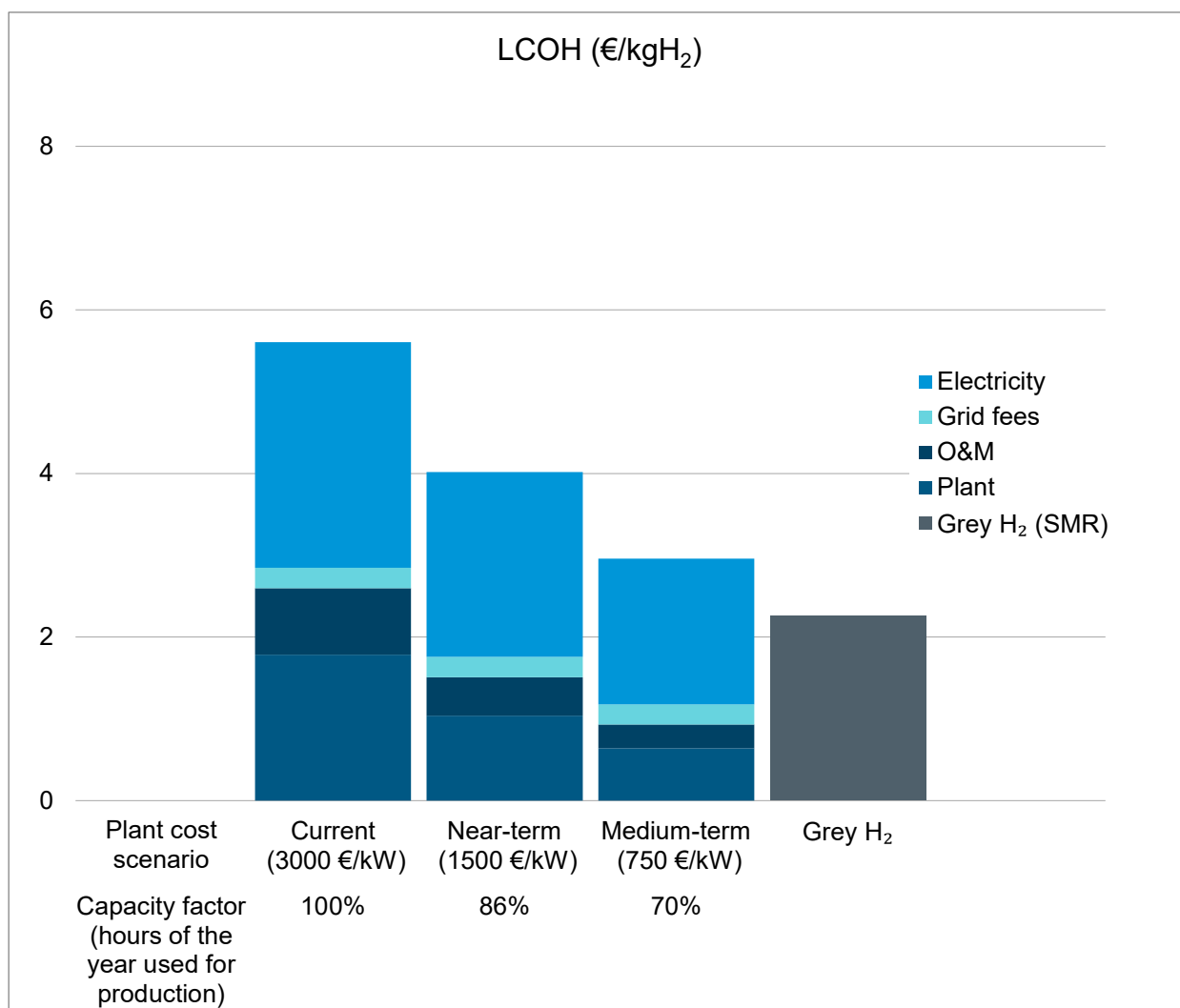
³⁹ Sector-wide analysis on hydrogen project deployment can be found in Hydrogen Europe 2024.

⁴⁰ Learning curves for electrolysers can be found in Way et al. 2022 and Bühler 2024.

⁴¹ This analysis assumes the producers of electrolytic LCF hydrogen are incentivised to schedule production so as to minimize the levelised cost of hydrogen, based on incentives setting a LCF hydrogen price close to the true minimum LCOH.

⁴² Data for 2024 plant costs are similar to TNO (2025); Data for 2030 projections of plant costs are based on NREL (2024); Data for 2035 projections are estimated from Bühler (2024).

Figure 8: Levelised cost of hydrogen for electrolytic pathways in France



Source: FCA analysis, ENTSO-E, TNO 2024, NREL 2024, IEA 2022, Bühler 2024

Note: The three cases shown represent *jointly* varying capacity cost, electricity cost and capacity factor. Electricity cost is determined by the optimum capacity factor, i.e., by operational strategy, which is in turn adapted to the capacity cost of the scenario, to yield the minimum LCOH. The electricity price distribution is unchanged for each case and based directly on 2024 ENTSO-E day-ahead market data. Underlying data and methodology can be found in the Annex.

At higher plant cost levels, the fixed costs – CAPEX and operation and maintenance costs – typically make up about 50% of LCOH. Electricity costs make up the other half, which is representative of the range of bidding zones presented in this draft. Additionally, there is a smaller contribution from grid cost reported for large French consumers, which shows more significant variation across cases, and will be discussed briefly below.

Operators are strongly incentivised to make as much use of an expensive electrolyser during the year as possible. This distributes the fixed capital costs over as many hours of production as possible. It also simplifies plant design as flexibility requirements for repeatedly switching electrolysers on and off can

increase costs and will require further development⁴³. As a result of near year-round operation, the average electricity cost for such a plant is close to the average annual spot market price. Using the spot market average for France the current plant cost scenario results in a LCOH of 5.8 €/kg.

When using the simplest form of a PPA, operators pay a fixed price for a guaranteed delivery of electricity that generally is slightly above the spot market average, but it also depends on the type of power generation contracted for. Especially firmed renewable power, i.e. renewable electricity provided at a fixed volume at all times, comes at a significant price premium⁴⁴. Due to the high investment costs, PPAs currently play an important risk management role in making project costs predictable. Furthermore, under RFNBO eligibility rules, renewable PPAs are frequently the only path to RFNBO certification, which makes it likely that an electrolyser will be at least partially covering its electricity input with a renewable PPA. They are also necessary to gain low carbon certification in some countries, as we will discuss below.

Electrolysis projects can achieve lower capital costs, mostly through technological learning and economies of scale in production and deployment. At the level of plant cost in the near-term scenario displayed in Figure 9, flexible operation becomes attractive when considering ways to lower LCOH. It allows selectively producing during hours with low electricity prices. This results in relatively higher fixed cost per unit of hydrogen production, as fixed costs are distributed over fewer hours, but it also results in lower average electricity costs. With an operational schedule optimised based on a simple maximum price heuristic (see annex for details), costs drop to 4.0 €/kg.

Technological learning curves for electrolysers are similar to those observed for solar PV, wind power, and battery costs⁴⁵. Extrapolating them to 2035 yields a representative estimated plant cost of 750 €/kW⁴⁶. In this scenario, flexibility has a large effect on minimum LCOH. Under the same maximum price heuristic employed in the near-term plant cost scenario, still assuming the 2024 electricity price distribution, most production in the model happens during hours when the price is lower than the median and results in costs of 2.7 €/kg, close to the modelled grey hydrogen cost of 2.3 €/kg.

4.3.2. Impact of limits on carbon intensity of grid electricity on cost

a. Limiting hours available for low-carbon hydrogen production

The LCOH estimates shown so far assumed full operational flexibility without limitations linked to the GHG intensity of the utilised electricity, as is the case for France. Table 5 in the DA annex shows that, in certain Member States, the average annual GHG intensity is also low enough for year-round LCF production under methodology (a) in Denmark, Finland, France, Lithuania, and Sweden, provided the efficiency of the electrolyser is above 68%. Except for Lithuania, the averages for these countries are

⁴³ Electrolyser operation discussed with experts from CATF (Wakim 2025).

⁴⁴ Flexible operation of electrolysers has been examined by Gusain *et al.* (2020) in *Technical Assessment of Large-Scale PEM Electrolysers as Flexibility Service Providers*. Further insight was gained through expert consultation (Wakim, 2025).

⁴⁵ Comparison of learning curves shown in Way *et al.* (2022).

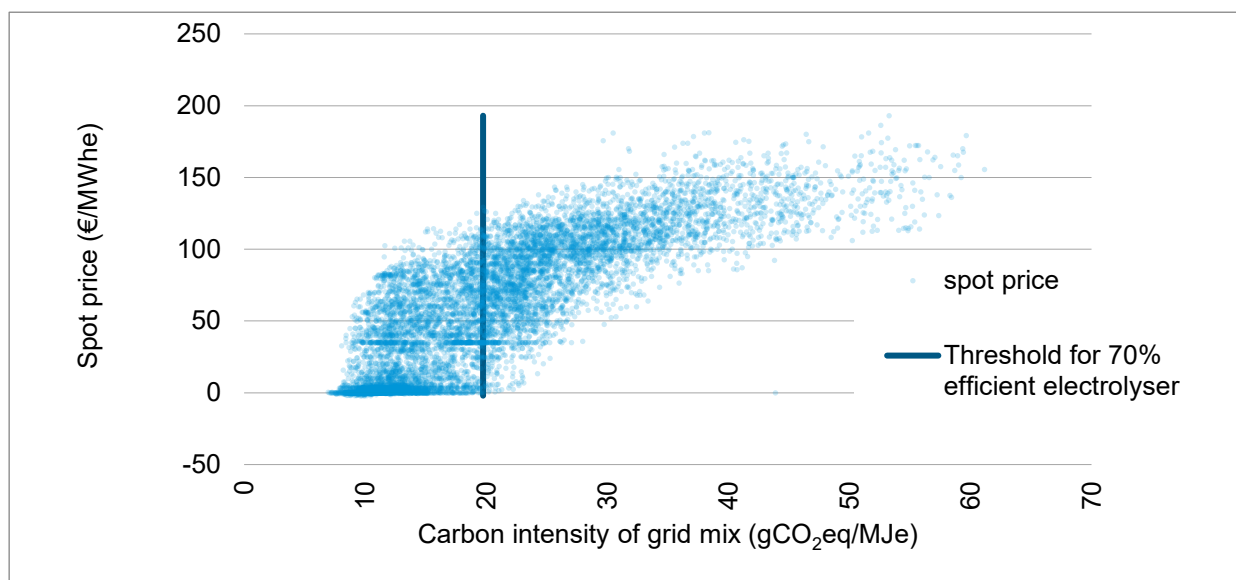
⁴⁶ Learning curves provided by Bühler (2024).

well below the threshold of 28.2 gCO₂/MJ for the final fuel, so a lower efficiency of 57% would also still be sufficient to meet it.

In other bidding zones with higher grid GHG intensity, electrolyzers will have to use one of the other three GHG accounting methodologies (b) (day-ahead hourly averages), (c) (previous year clean-hour proxy), and (d) (real-time marginal plant) to plan their LCF production. Our analysis shows that in most bidding zones, some significant fraction of hours will be excluded because grid intensity exceeds the DA threshold.

The more the applied DA rule forbids the use of otherwise low-cost electricity, the more it will increase the cost of production of low-carbon hydrogen compared to production solely based on cost-minimisation. Specifically, the exclusion of some hours has two effects: reducing the capacity factor below the plant cost specific optimum (fewer operating hours raise the capital cost per kilogram of hydrogen) and increasing the effective average electricity price⁴⁷ (excluded hours sometimes coincide with sufficiently low-cost electricity, pushing up the average cost of consumed power). As low-price periods are strongly correlated with low GHG intensity, the more price-selective the operational strategy of an electrolyser is, the less affected it will be.

Figure 9: Correlation of emissions intensity of electricity production and electricity price in Spain



Source: FCA analysis, ENTSO-E

Note: Each dot represents one hour in 2024. The position of the dot on the chart is determined by the spot price of that hour in the Spanish day-ahead market data and the estimated GHG intensity of the grid mix in that hour. The chart shows that the majority of hours with prices below 50 €/MWh are below the LCF threshold (dark blue line), while very few hours above 100 €/MWh meet the threshold. Detailed methodology can be found in the Annex.

⁴⁷ It is possible to ameliorate these effects via the rules on RFNBO hydrogen by using renewable PPAs, or to offset them via profits from selling conventional hydrogen produced at sufficiently low cost and large scale to make a profit. These possibilities will be discussed later in this document.

b. Choice of accounting methodology in bidding zones with higher grid GHG intensity

Low-carbon hydrogen producers will likely choose the GHG accounting methodology that allows maximising the number of operating hours eligible for LCF certification at a sufficiently low electricity price. It is beyond the scope of this report to consider all bidding zones and multiple electrolysis project configurations, but according to FCA's analysis, the three accounting methodologies (b), (c) and (d) will likely produce similar results under most circumstances, with the hourly average accounting method (b) being the most permissive as averaging allows hours with some fossil generation to remain below the threshold.

Methodologies (c) and (d) are based on the GHG intensity of the marginal or price-setting power plant in the bidding zone, i.e. the one having placed the highest bid for production that was still accepted by the market. Option (d) permits using near real-time data, ensuring precise correlation between production and marginal plant GHG intensity.

Option (c) can be seen as a low-granularity version of (d). It allows annual production over a number of hours equal to those when renewables or nuclear plants set the price in the previous year. Assuming that renewables and nuclear plants will set the price more and more frequently as grid GHG intensity lowers in the future, this is a conservative assumption. Furthermore, the hours chosen by the LCF producers using option (c) and the hours when renewable or nuclear plants are indeed price setting are very likely to align. This is because they will likely have lower prices than other hours due to the lower marginal cost of renewables and nuclear compared to fossil electricity⁴⁸. However, in most cases, there will still be hours that have sufficiently low electricity prices to meet economic criteria, but do not allow LCF production.

Methodology (b) involves using the GHG intensity forecasted by the transmission system operator two hours in advance of market closure, leaving time for dynamic production dispatch decisions. It permits strictly more hours to be used for production, because it involves averaging over all production types, meaning a mix with a fraction of fossil production can still come in under the threshold. Any such hours will likely have a fossil plant being the price setting plant, again due to the higher marginal cost of fossil electricity production. As such, it would have too high a GHG intensity under (d), and electricity would likely be slightly more expensive than the price in the most expensive hour still within the annually permitted number according to (c).

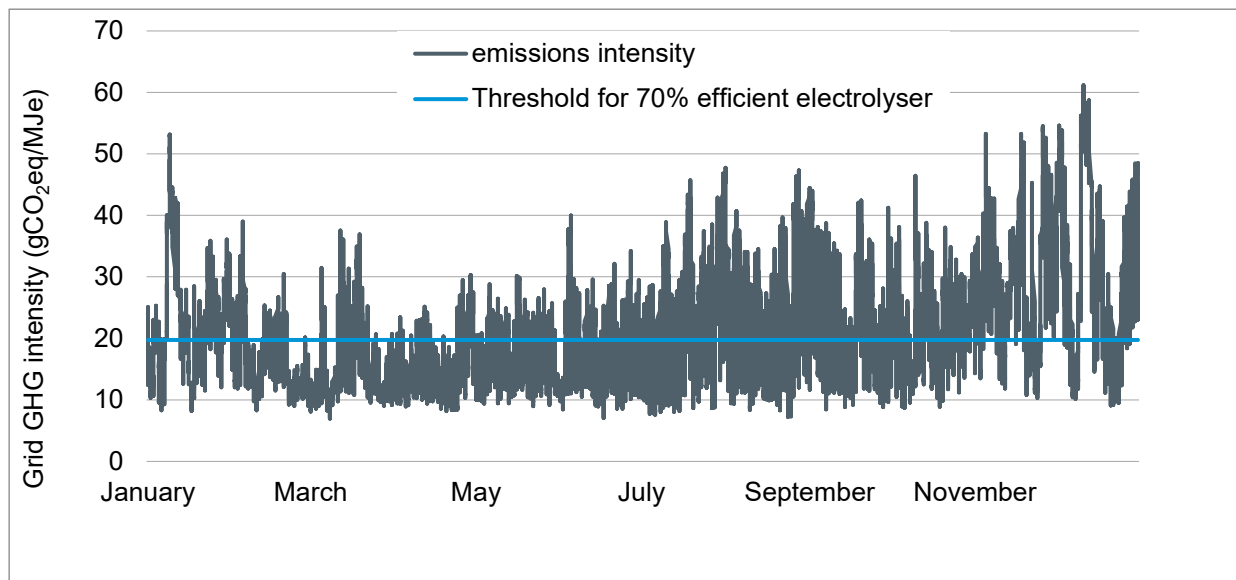
In summary, under most circumstances, GHG accounting methodology (b) allows using electricity in more hours of the year than (c) and (d), so it will be chosen for electrolytic low-carbon hydrogen production in bidding zones that have a higher annual GHG intensity average than permissible under methodology 6a. In most cases, it is also the most physically accurate methodology, so this will usually not lead to underestimating emissions.

⁴⁸ Note that this need not be the case if inflexibility causes fossil production to temporarily have a negative marginal price. Under such conditions, the correlation between low prices and low GHG intensities may be less pronounced, but they would also reduce the frequency of renewables or nuclear plants setting the price, meaning that this dynamic might be somewhat self-limiting.

c. DA effect on cost in bidding zones with relatively frequent hours of clean production

Even in bidding zones with high annual grid intensity, there are nonetheless frequently hours when the intensity drops below the DA threshold, permitting electrolytic LCF hydrogen production. Whether these hours align with periods having sufficiently low prices for the specific electrolyser affects the economic viability of LCF production. Figure 10 shows this is the case for Spain.

Figure 10: Emissions intensity of electricity production and electricity price in Spain in 2024



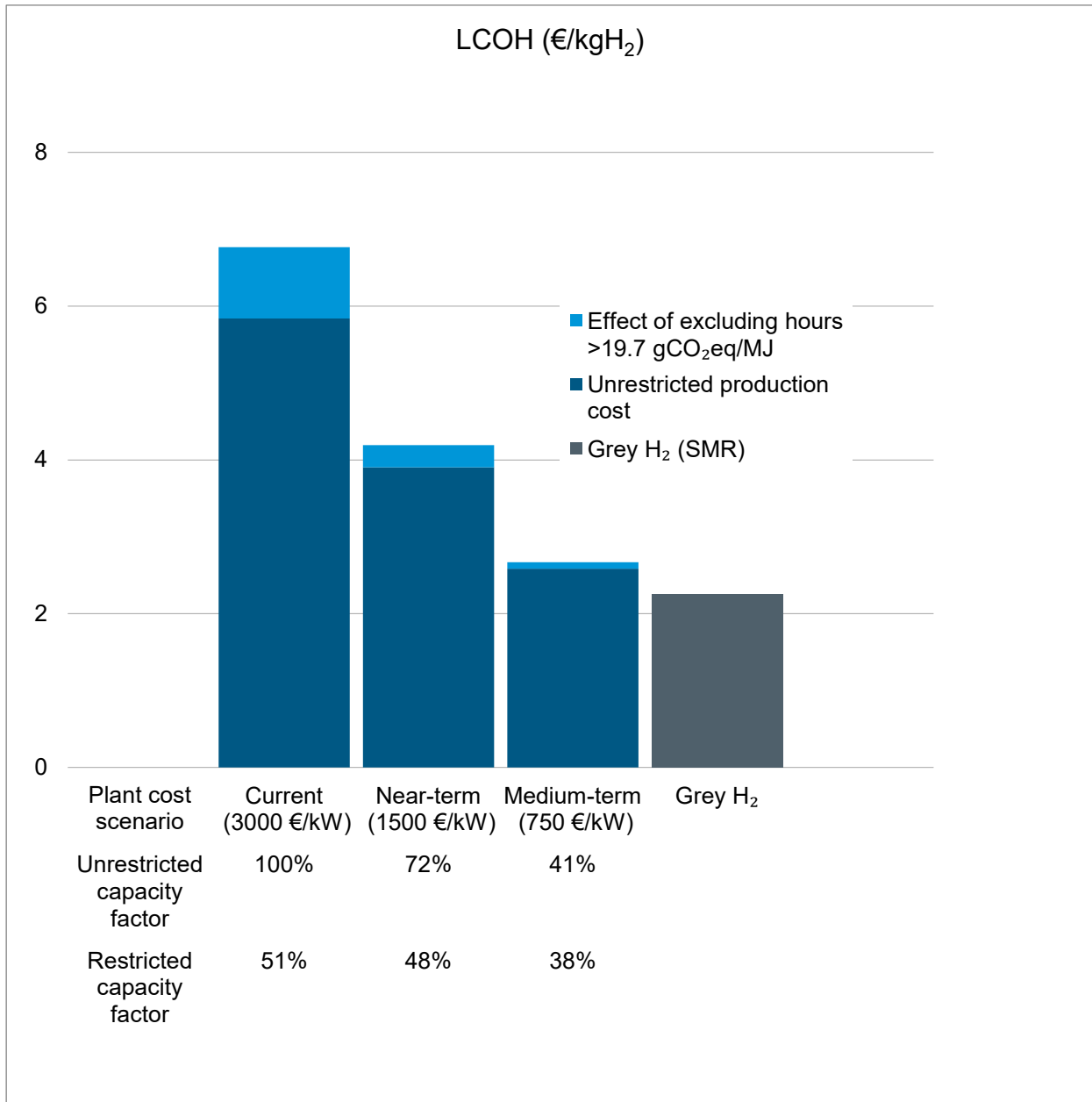
Source: FCA analysis, ENTSO-E

Note: Detailed methodology can be found in the Annex.

Figure 11 shows the LCOH for the electrolytic hydrogen production pathway in Spain, comparing the cost for unrestricted production and when hours with grid GHG intensity above the threshold are excluded following DA rules⁴⁹. As before, the costs are shown alongside a grey hydrogen benchmark and under the same three scenarios for capital costs and operational strategies described in section 4.3.1.

⁴⁹ In place of a GHG intensity forecast, this analysis uses the actual production data of 2024 provided by ENTSO-E and applies GHG intensity factors derived from literature (Agora, 2023) which are compatible with fuel-specific GHG values of the DA and typical conversion efficiencies for the respective technologies. Note that the analysis neglects the emissions from electricity imports as a simplification, implicitly assigning them a value of zero gCO₂eq/MJ. Accordingly, in practice the DA would restrict the use of a somewhat larger fraction of hours. The more price sensitive production becomes, the more production hours will align with low cost electricity though, which is generally associated with imported electricity also being low-emissions.

Figure 11: Effect of the DA on levelised cost of hydrogen for electrolytic pathways in Spain



Source: FCA analysis, ENTSO-E, TNO 2024, NREL 2024, IEA 2022

Note: Spain is chosen as an example of a bidding zone with hours of GHG intensity of production above and below the threshold. Underlying data and methodology can be found in the Annex, including graphs keeping CAPEX and other variables constant and comparing restricted hour cost distribution to unrestricted hours. Unrestricted capacity factor refers to 100% in the current cost scenario and the actual optimum in the other two, not to the heuristic optimum as shown for the example of France.

For the case without DA restrictions, the LCOH for Spain in this model is very similar to that of France in all three cases. This is due to the similar grid fees reported by large Spanish and French industrial consumers, on which the grid fee estimate of the model is based on, and the relatively similar average wholesale electricity prices for the three plant cost cases.

For the case with DA restricted hours, the cost is increased if operating hours are reduced. From an economic perspective, electrolyzers need high utilisation (capacity factor above 72% for the near-term scenario) to spread fixed costs efficiently. Each restricted hour increases the cost of hydrogen.

Notably, the impact of restrictions on LCOH is limited for the low plant cost case. The economics already push it towards lower capacity factors and selective production during a low electricity price hour, which are strongly correlated with low-emission hours. Essentially, the restrictions of the DA exclude few hours that would have been economical to use.

Note that in practice, electrolyzers would not simply reduce their annual hourly operations to comply with LCF limits. Instead, they may also contract renewable PPAs, which provide the option to effectively reduce the grid intensity in the GHG accounting by adjusting the input electricity mix with the addition of zero-rated renewable electricity, lowering the average.

Contracting a renewable PPA allows producers to reduce the average carbon intensity of their electricity for the DA calculation. The cost of hydrogen in such cases reflects a blended electricity price, for example combining the fixed cost of the PPA with the variable spot market price for any additional electricity purchased from the grid. This can be a compliance strategy in grids where average emissions are otherwise too high.

As the relative price difference between LCF and RFNBO hydrogen is not yet determined and will only become clearer once incentive mechanisms come into effect, determining an optimized lowest LCOH value for a partially PPA-based production case is not possible. We can nonetheless draw some tentative conclusions from an extension of our analysis (see Section 3d in the Annex for details).

PPAs providing renewable electricity as baseload (shaped PPAs) tend to be more expensive than pay-as-produced PPAs. In such a case, the LCOH for the LCF fraction produced from the grid will be very similar to the unrestricted results presented above, but the more hours of the year are above the threshold in terms of GHG intensity, the smaller that fraction will be. The rest would have to be more expensive RFNBO hydrogen production at near 100% capacity factor.

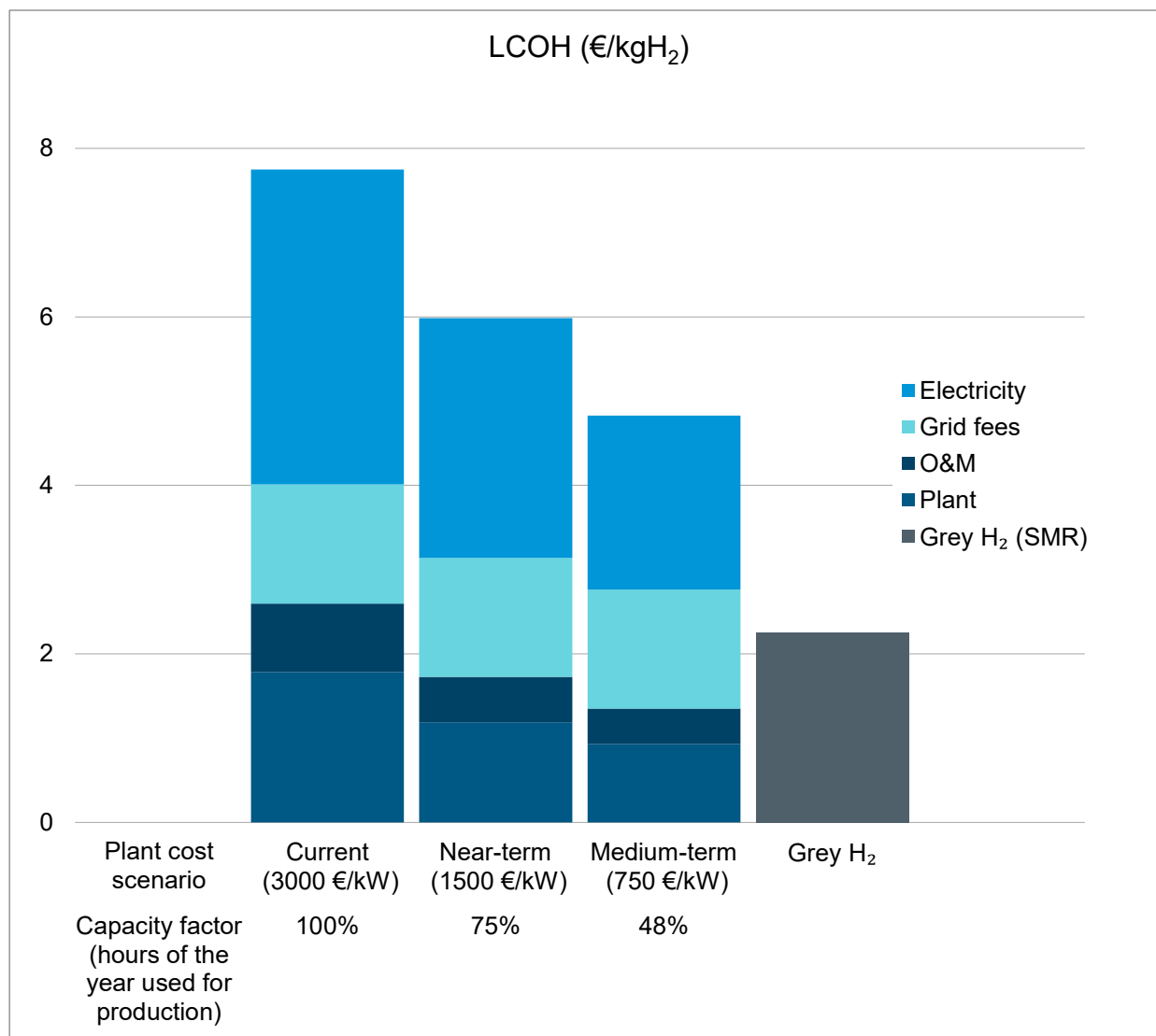
Using a lower cost pay-as-produced PPA, the costs would be relatively unaffected by the DA, as the correlation between renewable output and therefore the availability of PPA-supplied electricity with low electricity prices reduces the frequency of periods where grid electricity would be needed to supplement the PPA supply but prices are still low enough to make grid-based production economical.

d. DA effect on cost in bidding zones with few or no hours of sufficiently low carbon intensity of production

Figure 12 shows the LCOH for the electrolytic hydrogen production pathway in Germany for unrestricted production. As before, we show the three scenarios for capital costs and matching operational strategies described in section 4.2.2. In contrast to the cases shown for Spain and France,

reported grid costs for industrial consumers are more than five times higher in Germany. If grid costs were similar, LCOH would be comparable⁵⁰.

Figure 12: Levelised cost of hydrogen for electrolytic pathways in Germany (unrestricted production)



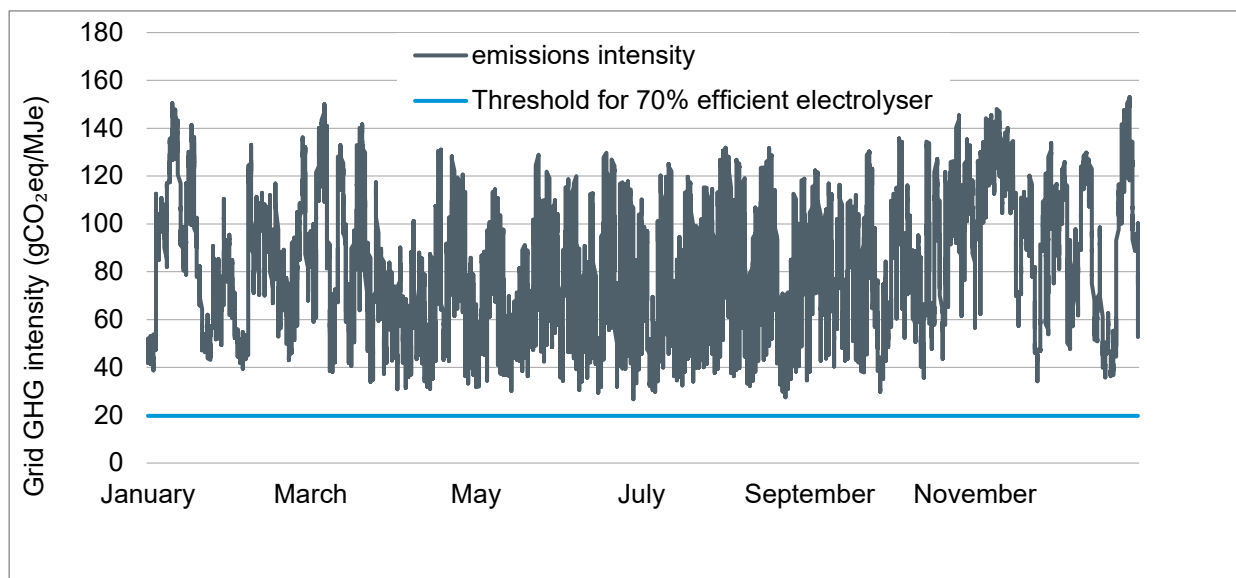
Source: FCA analysis, ENTSO-E.

Note: Underlying data provided in Annex. This does not include costs from restrictions of hours due to LCF thresholds, as GHG intensity in Germany is too high according to FCA’s estimate.

More importantly, according to FCA’s analysis, there were no hours in 2024 when the estimated grid GHG intensity in Germany fell below the DA threshold. Accordingly, just on the basis of the LCF GHG accounting methodology (b) alone, the production of electrolytic hydrogen meeting the LCF threshold with German grid electricity would not have been possible.

⁵⁰ Grid connection timelines are a major uncertainty factor in electrolysis project as well as others. Grid costs may rise across the Union in the future as the need for grid expansion rises further (Ember 2024). However, these questions are not touched upon by the DA, so they are outside the scope of this report.

Figure 13: Estimated GHG intensity of the German grid in 2024



Source: FCA analysis, ENTSO-E, Agora 2025

Note: Analysis neglects emissions from imports, actual emissions are higher.

Nonetheless, accounting options (c) and (d) might still enable LCF production. Any bidding zone with high average and hourly GHG intensities may still have hours with renewables or nuclear plants being marginal. However, this report does not analyse the market data required to determine which kinds of plants were price-setting in Germany or other bidding zones. In general, the overall effect of the DA restricting the hours available for production would remain.

As discussed for the case of Spain above, the economic response to this restriction is not simply reduced output, but to source a part of the electricity via renewable PPAs or directly connected renewables. This means producing LCF and RFNBO hydrogen in parallel.

The DA does not currently provide a mechanism for PPAs to supply low-carbon electricity for hydrogen production. Instead, it calls on the Commission to assess possible future alternative approaches for nuclear electricity. In practice, low-carbon PPAs would mostly mean nuclear PPAs, as natural gas power with CCS, the main alternative option, is unlikely to be financially viable for power generation, see section 3. One nuance to consider is that the DA does not prevent Member States from supporting low-carbon PPAs nationally, but such electricity would not count towards LCF certification under the DA methodology.

4.4. Outlook on future cost developments

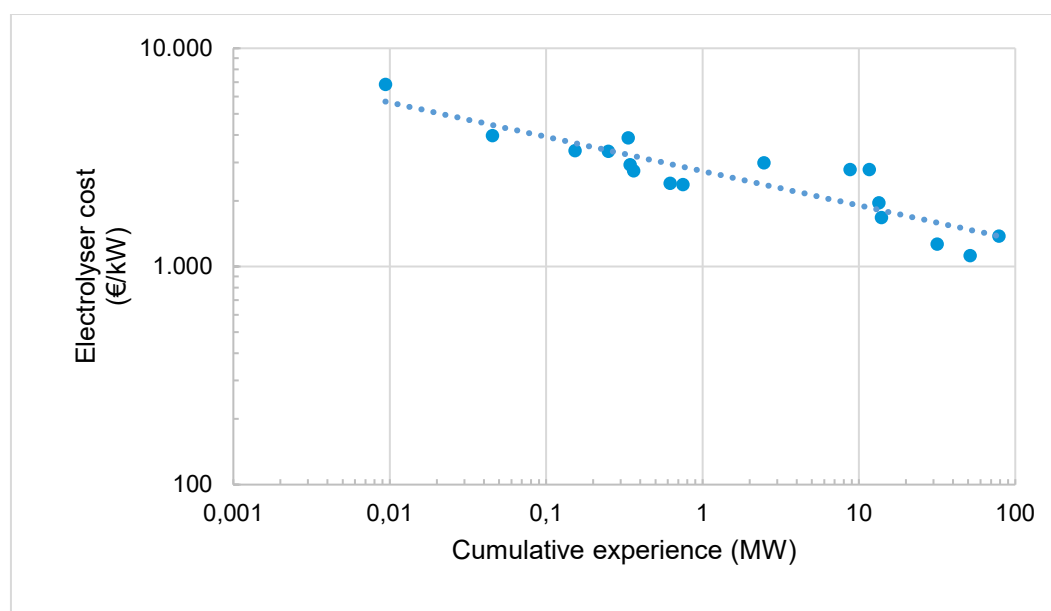
Comparing electrolytic hydrogen to blue hydrogen, the medium-term price developments of the former are more uncertain and dynamic, barring disruptive events in the gas supply. The trends that cause this uncertainty are the cost developments of electrolyzers, as shown in Figure 14, and the transformation of European grids, which affects the frequency of hours with low electricity prices⁵¹. On

⁵¹ Electricity price data provided by ENTSO-E (2025).

the other hand, despite the uncertainty of the electrolysis trendline, there are plausibly fewer risks for price increases as there are in the case of natural gas imports. The most significant risk for rising costs of electrolytic hydrogen probably lies in the aspect of grid costs⁵².

However, given the substantial cost advantage blue hydrogen currently has over low-carbon electrolytic hydrogen, electrolyser costs and electricity price developments have to closely mirror the large and often unexpectedly rapid price decreases observed for batteries and renewables⁵³. Current learning rates are no guarantee that this will occur, and electrolysers are potentially less amenable to mass production and modularity compared to e.g. solar PV, which is in part responsible though not decisive for the ongoing success of manufacturing cost decreases in solar, wind and batteries⁵⁴. On the other hand, Chinese electrolyser costs are reported to be as low as 1000 €/kW already today⁵⁵. While these figures may not fully reflect true costs, it is clear that the scale and ecosystem in which the value chain of electrolytic hydrogen production is embedded have a large influence. As a final note, it can be said that the degree of success electrolysers will have in emulating these examples is also determined by policy decisions, not just technological innovation processes alone.

Figure 14: Trend in Power-to-X electrolyser cost (CAPEX) between 2004 and 2020 as a function of deployment



Source: Data from Way (2022.)

⁵² Comprehensive analysis of Europe's electricity grid and the necessary changes for the transition are discussed by Ember (2025).

⁵³ A discussion on learning curves for various technologies is provided by Way et al. (2022).

⁵⁴ A discussion of what factors are conducive to rapid cost decreases is provided by Grubb (2022).

⁵⁵ Electrolyser costs in China are shown by Gong (2025).

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ANNEX 1: COSTING METHODOLOGY

This section outlines the costing methodology, underlying assumptions, and references used to estimate the costs of the blue hydrogen and electrolytic hydrogen production pathways.

All cost values are expressed in January 2025 Euros. Where necessary, values have been adjusted for inflation using the Chemical Engineering Plant Cost Index (CEPCI) and converted using 2025 exchange rates from the United Nations Operational Rates of Exchange.

1. Levelised Cost Equation

There are many methods to calculate the levelised cost of energy, applicable to both energy generation projects and the production of energy carriers. In this analysis, we follow the US National Renewable Energy Lab methodology, discussed by Aldersey-Williams et al. (2019). An advantage of this approach is that it avoids assumptions about long-term electricity and fuel prices, and hydrogen production levels. Instead, costs are modelled one year into the future without discounting future electricity costs or hydrogen production. Capital costs are then incorporated as annuitized annual payments, reflecting the need to generate profits or service loans.

Thus, the LCOH is calculated as,

$$LCOH = \frac{C_0 * CRF + O}{CF} + V$$

where, C_0 is the overnight capital cost, CRF is the capital recovery factor, O is the fixed operating cost, CF is the capacity factor, and V is the variable operating cost (e.g., fuel). The CRF is the equivalent annuity payment required to service the overnight capital, and is given by

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i is the interest rate and n is the project financing period (in years). In this analysis we assume an interest rate of $i = 7\%$ (after-tax WACC, real terms) and a financing period of $n = 15$ years, which gives a $CRF = 10.98\%$.

2. Cost assumptions for natural gas-based hydrogen production

The cost of blue hydrogen production is a key factor which will determine the extent of its deployment in future energy systems. However, the underlying cost values required for accurate analysis vary widely across the literature. In this study, the values applied are based on averages derived from the surveyed references. Tables 3–5 present the “best-estimate” input parameters deduced from this literature survey, while a more detailed breakdown will be provided in the accompanying Excel model of the final report.

Table 3: Technical parameters for blue hydrogen production methods

| Technical Parameter | SMR (Grey) | SMR + CCS | ATR + CCS | Units | Reference(s) |
|---------------------|------------|-----------|-----------|-------|----------------|
| Capacity factor | 95 | 95 | 95 | % | Assumption |
| Capture rate | 0 | 90 | 94 | % | (IEAGHG, 2022) |

Source: Included in the table.

Note: Capacity factor defined as the fraction of the year the plant is running – e.g., 95% corresponds to running for 8322 hours out of the total 8760 hours in a year.

Table 4: Net mass and energy flows, normalised per unit hydrogen produced

| Technical Parameter | SMR (Grey) | SMR + CCS | ATR + CCS | Units | Reference(s) |
|--------------------------|------------|-----------|-----------|--|----------------|
| Natural gas | 3.15 | 3.47 | 3.08 | $\frac{\text{kg}_{\text{CH}_4}}{\text{kg}_{\text{H}_2}}$ | (IEAGHG, 2022) |
| Oxygen | 0 | 0 | 3.19 | $\frac{\text{kg}_{\text{O}_2}}{\text{kg}_{\text{H}_2}}$ | (IEAGHG, 2022) |
| Net Electricity | 0 | 1.05 | 3.14 | $\frac{\text{kWh}_e}{\text{kg}_{\text{H}_2}}$ | (IEAGHG, 2022) |
| Captured CO ₂ | 0 | -8.89 | -8.24 | $\frac{\text{kg}_{\text{CO}_2}}{\text{kg}_{\text{H}_2}}$ | (IEAGHG, 2022) |

Source: Included in the table.

Note: Positive values are inputs to the system, and negative values are outputs. Despite the higher CO₂ capture rate of the ATR, the quantity of captured CO₂ is lower. This occurs because the total natural gas input to the ATR+CCS system is lower, as less natural gas is required for heating purposes.

Table 5: Economic parameters for blue hydrogen production methods

| Cost | SMR (Grey) | SMR + CCS | ATR + CCS | Units | Reference(s) |
|----------------------------------|---------------|--------------|--------------|---|---|
| CAPITAL COSTS | | | | | |
| Plant – Literature | 730 | 1300 | 1300 | $\frac{\text{€}}{\text{kW}_{\text{H}_2}}$ | (IEAGHG, 2022), (Oni et al., 2022), (Mullen et al., 2023), (US DOE, 2023), (IEA 2019) |
| Plant – Commercial | 1290 | 2300 | 2300 | $\frac{\text{€}}{\text{kW}_{\text{H}_2}}$ | (Air Products, 2025a), (Air Products, 2025b), (IEEFA, 2025), (Linde, 2024), (Collins, 2024) |
| Proportion of CAPEX due to CCS | 0 | 44 | 44 | % | (US DOE, 2023), (Mullen et al., 2023), (IEA. 2019) |
| OPERATIONAL COSTS | | | | | |
| Natural Gas Price | 40,70,100 | 40,70,100 | 40,70,100 | $\frac{\text{€}}{\text{MWh}_{\text{CH}_4}}$ | (Eurostat, 2024) |
| Electricity Price | 102 | 102 | 102 | $\frac{\text{€}}{\text{MWh}_e}$ | (Eurostat, 2024) |
| Gas Grid Cost | 1.65 | 1.65 | 1.64 | $\frac{\text{€}}{\text{MWh}_{\text{CH}_4}}$ | (Eurostat, 2024) |
| Operations and Maintenance (O&M) | 3.9 | 3.9 | 3.9 | % of CAPEX | (IEAGHG, 2022) |
| Transport and Storage (T&S) | 80 | 80 | 80 | $\frac{\text{€}}{\text{tonne}_{\text{CO}_2}}$ | (Smith et al., 2021), (CATF, 2025) |

Source: Included in the table.

3. Cost assumptions for electrolytic pathways

a. Capital costs

We assume a range of cases from literature with different CAPEX reflecting all installation costs. These serve as approximations for the years 2024, 2030, 2035, but also to cover the significant breadth of study results. There is substantial disagreement over plausible cost development curves, as discussed briefly in the main text. This is a clear limitation of our analysis, as the effect of plant costs are large and the resulting uncertainty is greater than the contribution from most other variables. We therefore adopt qualitative terms ('current', 'near-term', 'medium-term') as labels for the plant cost scenarios and caution the reader to interpret these scenarios as possibilities that are to a large degree contingent on technological and industrial policy.

In terms of annual fixed costs and project financing, we take a strongly simplified approach to facilitate comparing blue and electrolytic low carbon hydrogen on a level playing field representing scaled-up industries. We assume overnight construction and a capital recovery factor of 11%, based on a financing period of 15 years and 7% WACC (after tax, real terms). To the annual fixed costs resulting from this we add 5% for operation and maintenance (see IEA 2022). Again, the uncertainty from the abovementioned CAPEX projections is larger than what would result from changing these parameters across the full range of probable values.

For all scenarios we assume an efficiency of 70% (47.6 kWh/kg) for the electrolyser technology and unlimited flexibility for production starting and stopping on an hourly scale, which is one of the current technical advantages of proton exchange membrane (PEM) electrolysers. As mentioned in the main text though, cost projections for various types of electrolysis technology, including alkaline and solid oxide types, do converge within the limits of uncertainty of projections⁵⁶. The efficiency is slightly higher than current typical values for system efficiencies given in the literature (e.g. 60% / 56 kWh/kg as reported in 2024 by TNO) but we also do not model any progress in terms of efficiency, to keep the model more transparent and facilitate showcasing the effects of plant cost and hours available for production.

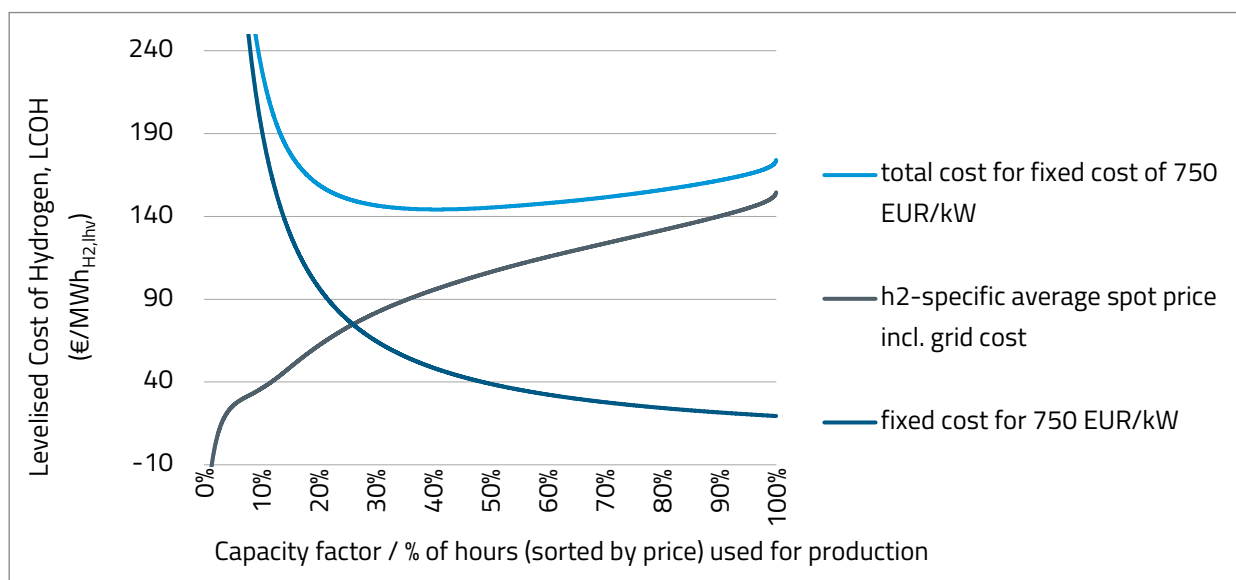
b. Operating costs

We use data for 2023 and 2024 spot prices (ENTSO-E day-ahead price data) to determine operating costs for each bidding zone. For the high-cost case (3000 EUR/kW), we fixed the capacity factor to be 100% representing current practice assumed to be using an inflexible PPA. This is slightly higher than what would be achieved in reality, given the need for planned and unplanned maintenance. As explained in the main text, lower plant costs allow for substantial reductions in average electricity prices. To optimize operations for the lowest annual LCOH, we ordered hours by price from lowest to highest for each plant cost scenario and bidding zone and determined the best combination of capacity factor and average electricity cost for 2023. This then served as a benchmark for the analysis of 2024.

⁵⁶ See Bühler's 2024 Review on experience curve concepts for electrolysis technologies - current status and perspectives.

We simulate heuristic dispatch for 2024 based on the benchmark of 2023, to show that uncertainty about future prices plays a minor role and that simple heuristics can be quite effective⁵⁷. In particular, the heuristic is based on not producing when the price rises above the maximum price paid in 2023 at the optimum capacity factor, reduced by 10%, reflecting the assumption of the electricity distribution changing year on year, making low prices more frequent, as shown by previous year's trends. This matches the actual optimum very closely, because in most cases the minimum in the curve describing total cost as a function of hours of the year (ordered by price) used for production is relatively flat, see Figure 15 below.

Figure 15: Levelised cost of hydrogen as a function of capacity factor



Source: FCA analysis, ENTSO-E.

Note: LCOH = Levelised cost of hydrogen. H2-specific means the spot price is adjusted for the efficiency of the electrolyser. Data shown is for Germany and 2024, using a grid cost of 29.7 €/MWh (Eurostat 2024).

Wholesale cost data like the day-ahead prices used here only reflect a part of the variable costs of electricity supply. In terms of technological aspects, grid fees represent the indispensable need to transport electricity, which is always associated with grid-supplied electricity. While grid fees are strongly regulated and therefore influenced by political decisions and not just technical necessity, it is important to include them⁵⁸. Other fees, taxes, and levies are explicitly excluded from this analysis however, to focus on the technical baseline on which political decisions of levels of taxation of different forms of energy are based. Due to the strongly varying levels of these additional costs between member states, both on electricity and natural gas, it is important to include these in further national analysis.

For future hydrogen prices to fully reflect the numbers calculated here would require policy that removes all tax incentives and burdens or related levies for electrolytic or blue/grey hydrogen and

⁵⁷ Heuristic production rule discussed by Brown et al. in *Price formation without fuel costs: The interaction of demand elasticity with storage bidding* (2025).

⁵⁸ We do not model hydrogen transport costs for either blue or electrolytic hydrogen.

potentially extends any benefit large steady electricity consumers have in terms of grid costs currently to large flexible consumers like electrolysers.

For the present analysis however, we only added a grid price component on a per MWh basis based on reported values from large industrial consumers⁵⁹ in the 2024 NRG_PC_205_C dataset from Eurostat. Several related limitations of our analysis have to be mentioned here. Actual grid costs are usually determined by load profiles and have yearly fixed components and dynamic components. Large consumers would at present likely not have a variable consumption as electrolysers modelled here do. Secondly, the wholesale price data average is generally lower than the average energy cost component given in NRG_PC_205_Cl. In some cases, this may reflect neglecting a fraction of electricity costs not related to taxes or fees. However most of this difference is due to the full exposure to the price variability we assume for flexible electrolysers in our analysis, which removes costs related to PPAs serving as a hedge against price volatility.

⁵⁹ Consumption of more than 150 000 GWh per year. Implicitly, this assumes all modelled electrolyser plants have a capacity of at least 17.1 MW (100% capacity factor), up to more than 85 MW (10% capacity factor).

Table 6: Grid cost component for electricity consumption of 150 000 MWh or over.

| Geographical area | Grid cost component (€/kWh) |
|---|-----------------------------|
| European Union - 27 countries (from 2020) | 0.0159 |
| Euro area (EA11-1999, EA12-2001, EA13-2007, EA15-2008, EA16-2009, EA17-2011, EA18-2014, EA19-2015, EA20-2023) | 0.0146 |
| Belgium | 0.0017 |
| Bulgaria | 0.0076 |
| Czechia | not available |
| Denmark | 0.0247 |
| Germany | 0.0297 |
| Estonia | 0.0000 |
| Ireland | 0.0059 |
| Greece | 0.0021 |
| Spain | 0.0051 |
| France | 0.0052 |
| Croatia | not available |
| Italy | 0.0088 |
| Cyprus | not available |
| Latvia | 0.0000 |
| Lithuania | not available |
| Luxembourg | not available |
| Hungary | 0.0227 |
| Malta | not available |
| Netherlands | 0.0362 |
| Austria | 0.0142 |
| Poland | 0.0348 |
| Portugal | 0.0080 |
| Romania | 0.0158 |
| Slovenia | not available |
| Slovakia | 0.0142 |
| Finland | not available |
| Sweden | 0.0055 |

Source: Eurostat 2024.

c. GHG intensity

To determine the effect of excluding hours with grid GHG intensity above the threshold for LCF production, we model dispatching electrolysers based on hourly GHG intensity forecasts, i.e. method (b) in the DA annex. Grid GHG intensity forecasts by the TSOs as they would have occurred in 2024 are approximated by estimating the actual GHG intensity of each hour in 2024. We do this by multiplying the (actual, retrospectively recorded) hourly production of each asset-class (as classified in the data from ENTSO-E) by asset-specific emissions factors provided in *Documentation V13* by Agora in 2023. The emission factors are shown in the following table and match the fuel-specific emission data of the DA when assuming typical efficiency values for the respective technology.

These emissions factors are broadly compatible with typical efficiency values and DA fuel emissions data. In the case of nuclear, the factor is based on the DA directly (using 33% eff. and the supplied value for nuclear heat).

Table 7: Emission factors used for hourly grid GHG intensity estimate.

| Asset class | Emission factor (tCO ₂ eq/MWh) |
|-------------------------------|---|
| Brown coal | 1.12 |
| Natural gas | 0.38 |
| Hard coal | 0.82 |
| All other fossil, incl. waste | 1.57 |
| Nuclear | 0.0054 |

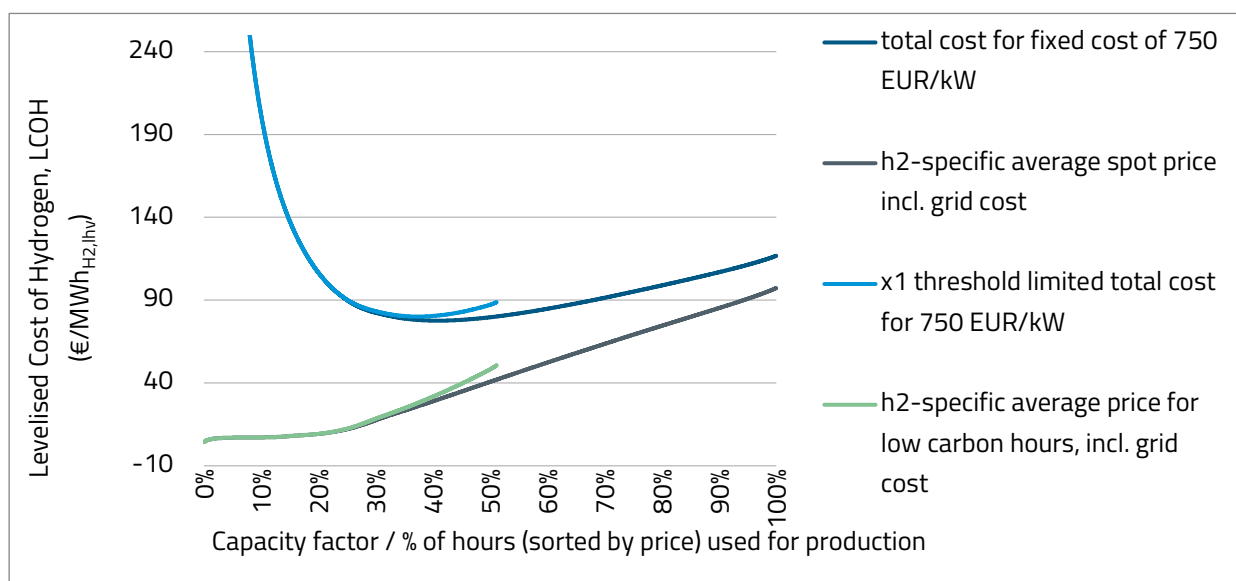
Source: Agora 2023, DA annex.

Again, several limitations must be pointed out: Most importantly, this model ignores import emissions completely, assigning zero emissions implicitly. In reality, fewer hours are available for LCF production in most cases, as the marginal hours just below the threshold would actually be above it if the GHG intensity of the imports were to be incorporated into the hourly average. However, the correlation between low price and low carbon intensity also means imported electricity tends to be of lower GHG intensity during these times, which offsets this effect somewhat, especially for low plant-costs and corresponding low capacity-factors of price-selective electrolysers. Besides the factor of imports, the use of asset-class averages across all bidding zones is less precise than a more thorough analysis of using fine grained emissions data for each plant at the respective load in the respective hour.

d. Initial estimate of impact of DA

To showcase the impact of the DA on the cost of LCF hydrogen, we exclude hours over the threshold from the analysis, sort remaining hours by price, and determine a new optimum. This optimum is generally at lower capacity factor than that for unconstrained production, esp. for high-CAPEX electrolyzers which need high-capacity factors to reduce costs. But the exclusion also affects low-cost electrolyser cases, e.g. in Spain, as some low-price but high GHG-intensity hours are excluded, requiring moving to the next more expensive-but-low GHG intensity hour. This effect is illustrated in Figure 16 below, where the grey curve (average price as a function of hours used for production i.e. capacity factor) starts to diverge from the green one (only averaging over prices with emissions below the threshold), as more hours are included. Note that the minimum of the total cost curve does not shift strongly (to lower capacity factors) and is still within the range of usable hours. This is not the case for high cost electrolyzers.

Figure 16: Levelised cost of hydrogen as a function of capacity factor and restriction of hours with high GHG intensity electricity production



Source: FCA analysis, ENTSO-E.

Note: LCOH = Levelised cost of hydrogen. H2-specific means the spot price is adjusted for the efficiency of the electrolyser. Data shown is for Spain and 2024, using a grid cost of 5.10 €/MWh (Eurostat 2024). The total cost curve results from adding the fixed cost curve (not shown) to the price curve. The restriction of hours (right end of light blue curve vs. end of dark blue curve at 100%) for low-cost electrolyzers does not exclude the economic minimum (of the light blue curve), as it does for high-cost electrolyzers. It only shifts it slightly to lower capacity factors and slightly up due to the small increase in average electricity cost (green curve vs. grey curve).

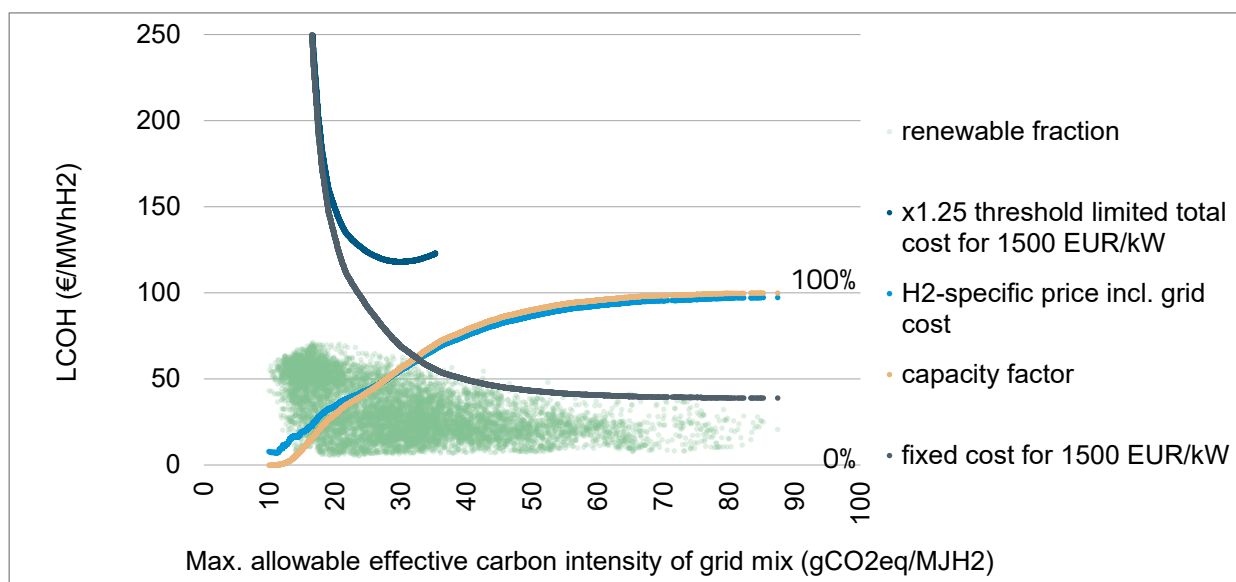
As discussed in the main text, simply not producing in hours that are not LCF compliant is an unlikely strategy to be adopted by electrolyzers. Instead, adding renewable electricity from shaped ("baseload"), pay-as-produced, or other PPA forms is more likely. This allows bringing down the average of the input electricity mix to be compliant. The effect on LCOH will be that utilization is increased, but average electricity costs will be higher than in the unrestricted case. Instead of a PPA, direct connected captive renewables may be used, essentially replacing the PPA cost with the levelised

cost of electricity and storage, if used. If the plant is not connected to the grid, grid fees would be reduced, but this may be (partially) offset by the lost opportunity to sell excess electricity to the grid.

In the next section, some illustrative calculations for PPAs are presented, but note that a true optimization of operational and electricity supply strategies is not possible without knowing the price difference between RFNBO and LCF hydrogen. Without this parameter, the ratio of production cannot be optimized. Accordingly, these results are only indicative.

e. Supplementary data

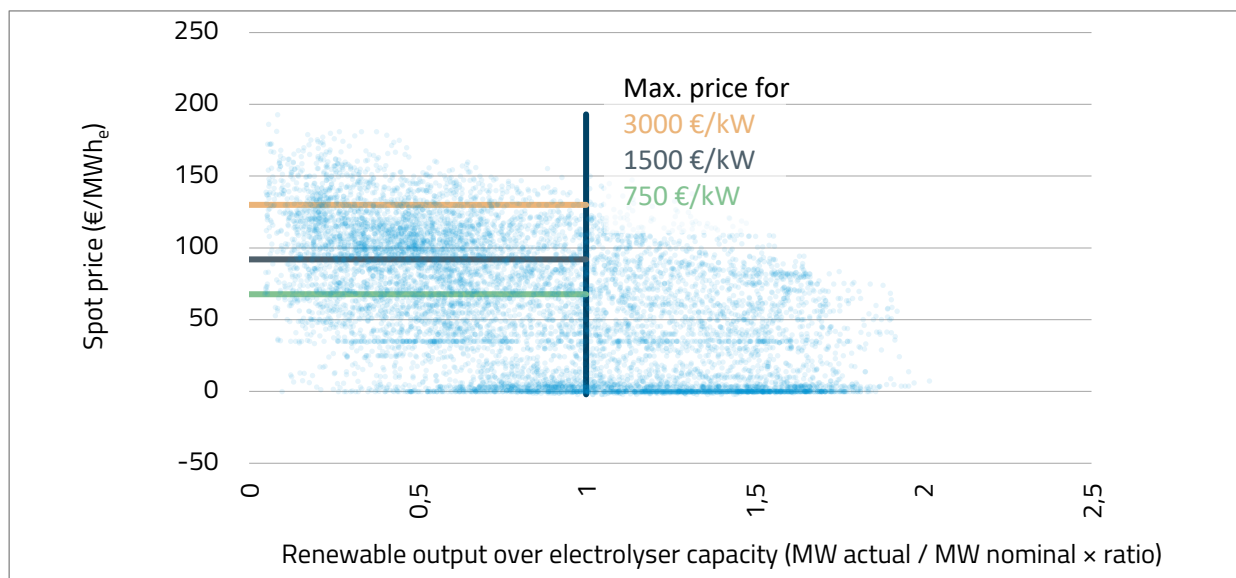
Figure 17: Illustrative calculations on baseload-PPA supplemented production



Source: FCA analysis, ENTSO-E.

Note: Supplying 20% of electricity by a renewable PPA at all times effectively results in raising the LCF threshold of 28.2 gCO₂eq/MJ_{H2} by a factor of 1.25. Accordingly, the dark blue curve for the total cost at the top goes beyond 28.2 gCO₂eq/MJ_{H2} to 35.25 gCO₂eq/MJ_{H2}. However, as this example shows, the benefit from being able to use more hours for the fraction of production from the grid has quickly diminishing returns in many cases. The change in capacity factor (and therefore the reduction in fixed cost per kg) levels off (yellow curve), and the electricity price component (bright blue curve) is already relatively high. This is also why the minimum of the total cost (dark blue curve) is actually at a lower capacity factor than this setup would enable in terms of hours below the LCF threshold that can be used. Notably, a large fraction of production will be RFNBO hydrogen due to the fraction of renewables in the grid supply. This again highlights that knowing the relative values of RFNBO and LCF hydrogen is necessary to optimize production setups in terms of operations and electricity supply arrangements. (Note that this does not model the possibility of partial load in hours that would be above the threshold at full load.) LCOH = Levelised cost of hydrogen. H2-specific means the spot price is adjusted for the efficiency of the electrolyser. Data shown is for Spain and 2024, using a grid cost of 5.10 €/MWh (Eurostat 2024).

Figure 18: Illustrative calculation on pay-as-produced PPA supplemented production.



Source: FCA analysis, ENTSO-E.

Note: Contracting for renewable supply as it is produced means the majority of production will be based on this electricity, with little being supplemented from the grid. In the example shown here, the ratio of electrolyser capacity to renewable output is set to 4. (Renewable output, i.e. $MW_{actual}/MW_{nominal}$, is estimated from the renewable output in each hour divided by the installed capacity in 2024.) In a large fraction of hours, supply will be more than sufficient to supply the electrolyser (dots to the right of the vertical line), and excess electricity may be marketed, but prices are usually low at these times. Note that most dots cluster in the dense region close to zero €/MWh. At other times, part of the electricity would need to be sourced from the grid (left of vertical line). The higher the cost of the electrolyser, the more it is worth accepting higher prices, as indicated by the three horizontal lines. The further leftwards a dot is in this area, the more grid electricity would be needed (100% at the left edge, 50% in the middle, 0% at the vertical line). Unfortunately, higher prices become more frequent in this direction as well. As a result, there are few hours where prices are low and grid electricity is needed and most of the production stems from the renewable pay-as-produced PPA. LCOH = Levelised cost of hydrogen. H2-specific means the spot price is adjusted for the efficiency of the electrolyser. Data shown is for Spain and 2024, using a grid cost of 5.10 €/MWh (Eurostat 2024).

4. Chemical properties

Table 8: Lower heating values of fuels

| Lower Heating Value | Value | Units |
|---------------------|-------|---|
| LHV _{H2} | 13.90 | $\frac{\text{kWh}}{\text{kg}_{\text{H2}}}$ |
| LHV _{CH4} | 33.32 | $\frac{\text{kWh}}{\text{kg}_{\text{CH4}}}$ |

Source: The Engineering Toolbox (2003)

ANNEX 2: GHG METHODOLOGY

B1. Oil Climate Index Method

The oil climate index combines results from three models for assessing upstream, transport, downstream and end-use emissions for the supply of oil and gas. These are:

1. OPGEE for emissions associated with resource extraction and transportation to the refinery/gas hub. OPGEE has been used as part of past exercises to characterise the carbon intensity of the EU oil supply for the EU Commission. For OCI, OPGEE assesses field-level flaring emissions based on allocating satellite observations of flare activity to the fields using geographical information.

Methane fugitives are estimated based on bottom-up modelling with default methane loss rates and assuming a flare efficiency of 91% (i.e. 9% of gas that leaves the flare tip is assumed uncombusted), except for countries where this is more tightly regulated where the efficiency is set to 98% (e.g. Norway).

Venting emissions are estimated using IEA methane tracker data at the national level, which includes methane from pipelines and LNG facilities. The fraction from pipelines and LNG is allocated into the 'gathering, storage and transport' term, but the OCI data does not provide a disaggregated LNG-related term. Transport distances have been based on making assumption about the gas distribution hub for each field based on following pipeline infrastructure – these distances do not necessarily reflect the distance to Europe.

2. PRELIM for oil refining. There are no refinery emissions associated with 'dry gas' processing, but some emissions associated with the natural gas liquids in wet gas streams.
3. OPEM, for "Oil Product Transport and Oil and Gas End Use Emissions". The modelling assumes that a percentage of ethane in natural gas is converted to ethylene for plastic feedstock, and it is our understanding that this is included in the "refining and petrochemical processing" term. OPEM also includes combustion emissions for the produced fuels.

Overall, we would expect that the production emissions intensity reported by OCI is broadly representative of the scope that is relevant to the DA, while the 'refining and petrochemical' emissions are outside that scope. The gathering, storage and transport emissions include a non-disaggregated term related to LNG (in both the CO₂ and CH₄ elements) such that the sum of the production and transport emissions from OCI will tend to give a slight overestimate in terms of the DA scope.

B2. Background data GHG calculation

Table 9: Implied pathway GHG intensity (gCO₂eq/MJ H₂) for low-carbon hydrogen with 93% carbon capture from different gas sources (GWP100)

| Natural gas source | Total methane loss rate | Uncaptured CO ₂ from reformer | CO ₂ e emissions from electricity for CC unit | CO ₂ emissions from natural gas production and transport* | Methane emission from upstream natural gas production | Methane emissions from pipeline transport of natural gas* | Other emissions | Total (gCO ₂ eq/MJ H ₂) |
|--------------------------|-------------------------|--|--|--|---|---|-----------------|--|
| Norway (Ormen Lange) | 0.83% | 5.2 | 0.7 | 9.0 | 3.8 | 2.8 | 1.5 | 23.0 |
| Norway (Gullfaks) | 0.22% | 5.2 | 0.7 | 14.6 | 1.8 | 0.0 | 1.5 | 23.7 |
| USA (Marcellus Ohio) | 0.83% | 5.2 | 0.7 | 9.0 | 5.0 | 1.6 | 1.5 | 23.0 |
| USA (Appalachia) | 0.72% | 5.2 | 0.7 | 11.2 | 3.8 | 1.9 | 1.5 | 24.3 |
| Algeria (Hassi R'Mel) | 1.00% | 5.2 | 0.7 | 10.1 | 5.5 | 2.4 | 1.5 | 25.4 |
| Algeria (Ohanet) | 1.97% | 5.2 | 0.7 | 15.9 | 13.6 | 2.1 | 1.5 | 39.0 |
| DA defaults, 93% capture | 0.88% | 5.2 | 0.7 | 6.3 | 7.0 | 0.0 | 1.5 | 20.7 |
| DA defaults, 86% capture | 0.88% | 10.4 | 0.7 | 6.3 | 7.0 | 0.0 | 1.5 | 25.9 |
| Source: | OCI+/DA | Bauer et al. | Bauer et al. | OCI+/DA | OCI+/DA | OCI+ | Bauer et al. | |

Source: FCA and Cerulogy extrapolation from Bauer et al. (2022) and OCI using GWP 100 *may include LNG-related emissions - these are not separated out in the OCI data

Table 10: Implied pathway GHG intensity (gCO₂eq/MJ H₂) for low-carbon hydrogen with 93% carbon capture from different gas sources (GWP20)

| Natural gas source | Total methane loss rate | Uncaptured CO ₂ from reformer | CO ₂ e emissions from electricity for CC unit | CO ₂ emissions from natural gas production and transport* | Methane emission from upstream natural gas production | Methane emissions from pipeline transport of natural gas* | Other emissions | Total (gCO ₂ eq/MJ H ₂) |
|-----------------------|-------------------------|--|--|--|---|---|-----------------|--|
| Norway (Ormen Lange) | 0.83% | 5.2 | 0.7 | 9.0 | 11.3 | 8.5 | 1.5 | 36.2 |
| Norway (Gullfaks) | 0.22% | 5.2 | 0.7 | 14.6 | 5.3 | 0.0 | 1.5 | 27.2 |
| USA (Marcellus Ohio) | 0.83% | 5.2 | 0.7 | 9.0 | 14.9 | 4.9 | 1.5 | 36.2 |
| USA (Appalachia) | 0.72% | 5.2 | 0.7 | 11.2 | 11.3 | 5.8 | 1.5 | 35.8 |
| Algeria (Hassi R'Mel) | 1.00% | 5.2 | 0.7 | 10.1 | 16.6 | 7.2 | 1.5 | 41.2 |
| Algeria (Ohanet) | 1.97% | 5.2 | 0.7 | 15.9 | 40.9 | 6.2 | 1.5 | 70.5 |
| Source: | OCI+ | Bauer et al. | Bauer et al. | OCI+ | OCI+ | OCI+ | Bauer et al. | |

Source : FCA and Cerology extrapolation from Bauer et al. (2022) and OCI using GWP 20 *may include LNG-related emissions - these are not separated out in the OCI data

The Delegated Act on low-carbon hydrogen establishes a harmonised, transparent framework, defining fuels in a technology-open way. It is essential for a functioning hydrogen market but does not create demand or financial incentives. Achieving emissions reduction target will hinge on robust methane emissions measurement and reporting. Costs will remain above unabated hydrogen, shaped mainly by natural gas and electricity prices.

This in-depth analysis was provided by the Policy Department for Transformation, Innovation and Health at the request of the ITRE Committee.

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