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Towards a Hydrogen Policy Reset in the EU

Eurogas recommendations

Eurogas calls on the European Commission to make the revision of the EU hydrogen production rules an immediate priority. In the short term, targeted measures should address the most pressing barriers to project development and strengthen investment certainty. These should include defering the phase-in of the additionality and hourly temporal-correlation requirements under the RFNBO Delegated Regulation, accompanied by robust grandfathering for early movers, and swiftly adopting a Q&A document clarifying the provisions of the Low-Carbon Fuels Delegated Regulation.
This should be followed by a broader, structural review of the EU production framework for both renewable and low-carbon hydrogen.
Without such a reset, Europe risks not only falling short of its hydrogen targets, including those set under the 2022 REPowerEU Plan and RED III for industry, but also weakening the ability of European industry to decarbonise in a cost-competitive manner and becoming more resilient by diversifying energy and feedstock sources

Introduction

The European Union has placed hydrogen at the centre of its decarbonisation strategy with an expected critical role especially in decarbonising hard-to-abate sectors, strengthening energy security and supporting industrial competitiveness. Through the EU Hydrogen Strategy and the REPowerEU Plan, the EU has established ambitious targets, including 40 GW of electrolyser capacity and 10 million tonnes of domestically produced renewable hydrogen by 2030.

However, despite these ambitions, **the development of the European hydrogen market remains far behind expectations**. Progress in electrolyser deployment has been limited, with operational water electrolyser capacity ranging between 308 and 571 MW and approximately 1.8-2.8 GW under construction[1]: a minuscule fraction of the capacity required to meet the EU's 2030 objectives. **Recent assessments by the Agency for the Cooperation of Energy Regulators (ACER)[2], the International Energy Agency (IEA)[3], and the European Court of Auditors (ECA)[4] all point to the same conclusion: Europe is not on track to achieve its hydrogen targets**.

[1] ACER, European hydrogen markets, 2025 Monitoring Report and Hydrogen Europe, Clean Hydrogen Monitor (2025)
[2] ACER, Decarbonisation of the EU's natural gas market, 2026 Monitoring Report (page 13).
[3] IEA, Global Hydrogen Review (2026): *In the European Union, installed electrolyser capacity would need to grow by a factor of 70 to meet the ambition set in the EU Hydrogen Strategy.*
[4] European Court of Auditors, Special Report, The EU's industrial policy on renewable hydrogen: *We found that the production target of 10 Mt, which may require up to 140 GW in terms of electrolyser capacity (input), is unlikely to be met.*

While multiple factors contribute to this gap[5], an increasing number of market assessments suggest that **the regulatory framework governing hydrogen production has become one of the main obstacles to market development**. For renewable hydrogen, the production rules established under the Renewable Fuels of Non-Biological Origin (RFNBO) framework have significantly increased production costs and constrained project development. ACER (2025)[6] estimates that the average cost of RFNBO hydrogen remains significantly higher (EUR 8/kg) compared to just above EUR 2/kg for conventional hydrogen.

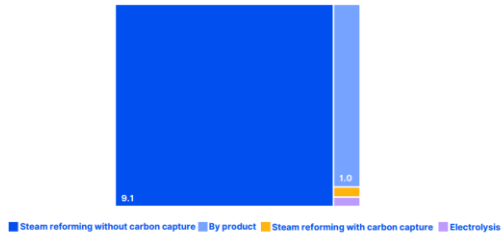
At the same time, the regulatory framework for low-carbon hydrogen has failed to provide a credible pathway for investment and deployment. Despite offering substantial greenhouse gas emissions reductions and production costs potentially significantly below those of renewable hydrogen, low-carbon hydrogen remains largely absent from the European market. In the case of blue hydrogen, while we acknowledge that its deployment will also depend on the availability of CO_2 transport and storage infrastructure, market experience indicates that some of the main barriers currently stem from the regulatory framework. This framework also fails to recognise the potential of solid carbon as emissions reduction material. In this context, low-carbon hydrogen already suffers from limited recognition in EU legislation and restricted access to eligible end-use markets, the production rules established under the Low Carbon Fuels Delegated Regulation further exacerbate the barriers in the market. In particular, economic operators struggle to comply with its requirements and, therefore, hesitate in taking any Final Investment Decisions (FIDs). Rather than enabling deployment, they have failed to create the regulatory certainty and investment conditions needed to scale up projects and support the EU's climate and industrial ambitions.

The situation is equally challenging for biohydrogen[7]. Despite its significant decarbonisation potential, the current regulatory framework neither recognises biohydrogen nor provides any dedicated incentives for its deployment.

As a result, both low-carbon hydrogen and biohydrogen, although important decarbonisation pathways, remain overlooked, limiting the range of solutions available to enable earlier emission reduction, scale-up new demand, support infrastructure development, and achieve the EU's climate objectives. This should be addressed as a matter of priority in the upcoming post-2030 renewable energy framework.

[5] Barriers to the development of a European hydrogen market should be assessed across the full value chain, taking into account the challenges affecting production, demand, and infrastructure. On the demand side, for example, delays and differences in the transposition of RED III across Member States create regulatory fragmentation, weakening investment signals and slowing the emergence of a truly integrated EU market.
[6] ACER, European hydrogen markets, 2025 Monitoring Report (page 40).
[7] Biohydrogen should be understood as hydrogen whose energy content is derived from biomass fuels, either through electricity produced from such biomass fuels or through the direct use of biomass-derived molecules.

Figure 5: Hydrogen production capacity by process type in the EU – 2024 (Mt/y)



Source: ACER, based on data from the European Hydrogen Observatory.

Note: For the annual hydrogen production capacity for electrolysers European Hydrogen Observatory assumes nearly 100% utilisation rate.

The consequences of this regulatory approach are becoming increasingly evident. From an environmental perspective, hydrogen production today remains responsible for an estimated 70 to 100 million tonnes of GHG emissions annually in the EU (Gas for Climate). Yet, **the regulatory framework intended to accelerate the transition to low-carbon alternatives is, in practice, leading to an extremely serious missed opportunity**. Beyond the emissions associated with hydrogen production itself, it is also delaying significant decarbonisation gains by limiting hydrogen deployment in industrial processes where it could already replace conventional fuels across Europe. Hydrogen also adds value to the energy system by providing long-duration storage and flexibility, helping to balance variable electricity generation. In particular, electrolyser operation can absorb surplus renewable electricity, reduce curtailment and grid congestion, and support a more cost-efficient and secure integration of renewables.

Building a decarbonised hydrogen market first, where RFNBO, low-carbon hydrogen and biohydrogen can all contribute, will allow to increase renewable hydrogen volumes as costs decline and deployment mature. Against this backdrop, **a revision of the EU hydrogen framework should become an immediate priority**. Such reform should be pursued in two phases. First short-term relief should be provided to remove the most pressing barriers to project development. Second, the EU should undertake a broader and more fundamental review of its hydrogen policies to create the conditions necessary to unlock investment across both renewable and low-carbon hydrogen pathways.

Without such a reset, Europe risks falling short not only of its hydrogen targets, but also of the wider industrial, energy security and climate objectives that hydrogen is intended to support.

RFNBO Delegated Regulations

Background information: the impact of the criteria on the European hydrogen market

The application of the **additionality, temporal correlation and, for some Member States, also geographical correlation requirements** constitute a significant barrier to the development of the RFNBO market. These criteria increase regulatory complexity, constrain the operational flexibility needed to optimise production, and substantially raise compliance and production costs. As a result, they **undermine the commercial viability of RFNBO projects and hamper the scale-up of the sector across the EU**.

The key challenges associated with each requirement are outlined below.

Additionality

Requirement to source renewable electricity from new installations

- This requirement significantly limits electricity sourcing options. PPAs linked to new renewable installations are often the most expensive option, as the available pool of renewable electricity is limited while demand for compliant power continues to increase, and renewable electricity producers tend to request a premium for the "additionality".
- Renewable energy developers typically require long-term PPAs (often around 15 years) to secure project financing. Hydrogen projects must therefore provide substantial financial guarantees, such as parent company guarantees or other collateral to meet this request, further increasing production costs.
- Infrastructure constraints also play an important role. Grid congestion, connection bottlenecks, and lengthy permitting procedures, particularly for onshore wind projects, limit developers' ability to optimise procurement strategies and secure sufficient renewable electricity supply.

Restriction on subsidised renewable electricity

- As most new renewable projects currently rely on public support schemes, this requirement significantly reduces the pool of eligible electricity sources for RFNBO production, increases costs, and does not improve market scalability.
- Contracts for Difference (CfDs) are often more attractive to renewable developers than PPAs, further limiting the availability of eligible renewable electricity for RFNBO projects and potentially increasing PPA costs.
- In addition, CfDs do not always cover the full output of a renewable installation, leaving only part of the production available for PPAs. This may require RFNBO producers to contract electricity through multiple PPAs, increasing complexity and transaction costs. However, even the share of output that remains available for PPAs is often considered ineligible, as Delegated Regulation (EU) 2023/1184 refers broadly to "subsidised installations" rather than to "subsidised production".

36-month commissioning timeline

- The commissioning timeline is not always aligned with current permitting procedures and grid connection realities.
- Administrative concessions and grid capacity allocations for renewable electricity projects are not aligned with the commissioning timeline of associated hydrogen projects. Renewable installations such as wind or PV can be built in less than 2 years whereas RFNBO plants take 3-4 years. This entails a significant project risk, as the investment decision for the two plants do not match in time.

Temporal correlation

Hourly temporal correlation also remains a major barrier to market development, as it currently significantly **impacts electrolyser utilisation rates**. By limiting electricity sourcing to periods of renewable generation, it lowers hydrogen output while fixed investment costs remain unchanged, thereby undermining project economics. In particular, in hours without sufficient matching generation, production must be reduced or cannot qualify as RFNBO, lowering full load hours, and increasing the need for oversized PPA portfolios, storage and back-up supply.

Geographical correlation

Finally, the geographical correlation requirement poses **significant challenges in Member States that are divided into multiple bidding zones**. In these countries, renewable electricity generation and RFNBO production facilities are often located in different bidding zones. In Italy for instance, renewable electricity generation is typically concentrated in the south, where solar and wind resources are most abundant, while RFNBO production is more likely to be situated in the north, closer to industrial demand centres and existing infrastructure.

Short term regulatory fixes

The market uptake of RFNBOs in Europe remains significantly below expectations. As highlighted by ACER[8], RFNBOs currently represent only a negligible share of the market, and the sector is not on track to meet the EU's REPowerEU 2030 targets. Investment and production volumes remain limited, while project developers continue to face considerable challenges in complying with the stringent requirements established under Delegated Regulation (EU) 2023/1184.

Without targeted adjustments, these provisions risk further constraining the development of the RFNBO market at a time when accelerated deployment is urgently needed.

For these reasons, it is essential to **provide short-term regulatory relief** to support market development, facilitate investment decisions, and enable the scale-up of RFNBO production. In this regard, Eurogas recommends to:

1. **Postpone the additionality requirement until 2035.** Projects that begin operation before 2035 should be exempt from this criterion for their entire lifetime. As frontrunners in a nascent market, these projects should benefit from regulatory flexibility to enable early deployment.

2. **Postpone the hourly temporal correlation requirement until 2035**. Projects that begin operation before 2035 should be exempted from this criterion for their entire lifetime.

Projects and installations established before the entry into force of the simplified Delegated Regulation should benefit from **grandfathering provisions**, to avoid competitive disadvantages compared with newer projects developed under more flexible rules. We see two possible solutions to materialise these safeguards:

- **Financial solution for early movers:** provide financial compensation to projects operating under the current framework, for example through exemptions from grid tariffs or certain levies, or through lump-sum support to offset higher production costs.

[8] Decarbonisation of the gas sector report

- **Market-based solution:** while financial compensation can be an effective tool to support early movers investing in RFNBO production, it also has important limitations. First, its implementation is left to the discretion and implementation timelines of Member States, fragmented approaches and potential delays. Second, public financial resources are limited, making such measures difficult to sustain over the long term. In this context, market-based mechanisms, such as multipliers, could be an alternative solution to ensure that projects benefit from grandfathering.

Long-term structural revision

While short-term relief measures are necessary to address the immediate challenges facing the RFNBO market, they should be accompanied by a broader reflection on the long-term effectiveness of the current regulatory framework. **More structural amendments to Delegated Regulations (EU) 2023/1184 and 2023/1185 should therefore be considered** to improve the workability of the rules, reduce unnecessary barriers to deployment, and provide the regulatory flexibility needed to support the scale-up of the RFNBO market.

Delegated Regulation 2023/1184

- **Electricity sourced from *new* renewable installations**: Electricity from existing renewable generation assets should also be eligible to supply electrolysers, as restricting sourcing to new renewable capacity unnecessarily limits project development. This is particularly relevant in the PPA market, where a more stable or baseload supply profile is often achieved by pooling different energy assets, such as renewable generation and storage. Legacy renewable assets, including hydropower, can therefore play an important role in supporting such portfolios by providing a more flexible, reliable and cost-effective renewable electricity supply for RFNBO production.
    - *Example from Italy*: hydropower is the main renewable resource capable of supplying electricity during nighttime hours, yet meeting the additionality requirement for such assets is particularly challenging.
- **Electricity sourced from subsidised renewable installations**: In the case in which the additionality criterion applies to an electrolyser, the use of renewable electricity generated by installations that have received public support should not be excluded a priori if overcompensation is prevented. This could be achieved, for example, by ensuring that the renewable energy installation and the electrolyser are not receiving public support at the same time, by discounting public support already received for energy production from the subsidy awarded to the electrolyser, or by giving electrolyser operators the option to opt in to or opt out of support schemes. This would provide the flexibility to source renewable electricity from supported renewable generation assets while ensuring that RFNBO production does not benefit from undue levels of public support.
- **Hourly electricity price below EUR 20/MWh**: The additionality requirement should be lifted when the hourly electricity clearing price in Single Day-Ahead Coupling (SDAC) falls below €20/MWh, or is equal to or lower than 0.36 times the CO_2 price. In such cases, the electricity consumed should be presumed renewable without further proof. At these price levels, fossil-based electricity generation

is not an economically viable option. The market price therefore already provides a strong signal that the electricity consumed during those hours is predominantly renewable.

- **90% renewable electricity threshold**: Under the current Delegated Regulation, electricity is considered fully renewable where the average renewable electricity share in a bidding zone reaches 90%. In such cases, electrolysers are exempted from complying with the remaining electricity sourcing requirements. However, this threshold is unlikely to be achieved in the near term by many Member States, limiting the practical applicability of this provision. We therefore recommend adopting a more gradual and realistic trajectory, with the threshold set at 80% in 2030, increasing progressively to 82.5% in 2035, 85% in 2040, 87.5% in 2045, and ultimately reaching 90% by 2050. This phased approach would better reflect the pace of power system decarbonisation across the EU while maintaining a clear long-term objective. Additionally, recognising verified renewable electricity imports, which are currently treated as fossil-based, would make the threshold more achievable and better reflect the integration of the European internal electricity market.

- **Geographical correlation**: The Delegated Regulation should allow electricity supplied through a PPA to qualify where the renewable electricity generation installation is located in a different bidding zone within the same Member State.

Delegated Regulation 2023/1185

- **Technical alignment with Delegated Regulation 2025/2359:** The Delegated Regulation should be aligned as soon as possible with the GHG emissions accounting provisions for electricity consumption by renewable hydrogen installations set out in Delegated Regulation 2025/2359 (Annex A.6). Such alignment would allow for a more accurate and granular assessment of emissions associated with electricity use, better reflecting the actual GHG intensity of the electricity grid. Similarly, the carbon sourcing rules set out in Delegated Regulation 2023/1185 (Annex A.10) should be aligned with the broader spectrum of sources that is established under Delegated Regulation 2025/2359 (Annex A.10). This change would increase the technical potential for their integration into synthesis processes, while helping to address process complexity and overcome existing technological barriers.

- **Sunset clause for CO_2 sources:** According to the current text, CO_2 emissions from industrial sources would no longer be recognised as avoided emissions for RFNBO production from 2041 onwards (and from 2036 for CO_2 originating from the combustion of fuels for electricity generation). We recommend the possibility to reuse this captured carbon past the 2041 date or, alternatively, introducing a 20-year grandfathering provision for projects that enter into operation by 2040. Indeed, this provision undermines the economic viability of projects relying on industrial CO_2 streams. While the deployment of atmospheric and biogenic CO_2 should be accelerated and supported through appropriate policy measures, their large-scale availability remains uncertain in the medium term. Finally, the proposed timeline does not adequately reflect the reality of European industrial installations that will continue to generate unavoidable process emissions. Many of these facilities are unlikely to have timely access to permanent CO_2 storage infrastructure and will therefore depend on carbon capture and utilisation (CCU) solutions as an essential decarbonisation pathway.

Low-Carbon Fuels Delegated Regulation

Short term regulatory fixes

Almost one year after the adoption of the Low Carbon Fuels Delegated Regulation, significant uncertainty remains across the sector due to **a number of provisions lacking sufficient legal clarity that represent a concrete barrier to the materialisation of projects in the EU**.

This has direct negative consequences on the certification of low-carbon fuels as, to date, no certification scheme for low-carbon fuels has been developed, let alone accredited by the European Commission. Without such a framework in place, certification schemes cannot be established, particularly for CCS-based low-carbon hydrogen and fuels.

Eurogas considers the following outstanding issues to be priorities for clarification through the **swift adoption of a Commission's Q&A Document**:

Grandfathering clause	
Low Carbon Delegated Regulation provision	***Open questions***
Article 3 establishes that '*when assessing changes to the criteria the Commission shall safeguard existing projects*'.	**(?)** Uncertainty regarding the **scope of the grandfathering clause**, specifically whether it applies only to changes in default values or also to other elements of the text.
	(?) Lack of clarity on the **definition of 'existing projects**,' including whether it covers, i.e., projects with FID, under construction, or already operational. In case of existing SMRs for the production of blue hydrogen, the CO_2 capture plant should also be existing.

Biofuels, bioliquids and biomass fuels used as part of a 'delineated process'	
Low Carbon Delegated Regulation provision	***Open questions***
Annex A.1 (sixth subparagraph) refers to **biofuels, bioliquids and biomass fuels used as part of a 'delineated process'** (as per footnote 2).	**(?)** Clarification needed on the **interpretation** of this provision.

Future inclusion of low carbon fuels under the Union database	
Low Carbon Delegated Regulation provision	***Open questions***
Recital 3 indicates that '*raw materials used for the production of low-carbon fuels as well as the low-carbon fuels themselves should be traced via the Union database*	**(?) Clarifications on the implementation** of such intention under the Union Database and the link with the

in the same way as raw materials used for the production of renewable fuels and the renewable fuels themselves'.	methane emissions import requirements (currently being discussed) are needed. Additionally, we encourage the European Commission to **establish a swift accreditation of low-carbon certification schemes** in order to boost the necessary development of low carbon fuels projects.

CCUS-related provisions	
Low Carbon Delegated Regulation provision	***Open questions***
• The Delegated Regulation foresees that permanent geological storage in third countries shall be recognised where legal obligations on MRV and remediation of leakages are in line with EU legislation (Annex A.17). • Recital 5 also establishes the potential future recognition of storage of EU ETS emissions in storage sites in third countries, provided that *'equivalent conditions to ensure permanently secure and environmentally safe geological storage of captured CO_2 storage'* exist.	**(?)** Uncertainty on when and how **equivalence** between third countries' and EU rules would be established for MRV and leakage remediation in permanent geological storage sites. **(?)** Lack of clarity on the '***equivalent conditions'*** that third countries must meet to ensure permanent and environmentally safe CO_2 geological storage.
Annex A.17 foresees that '*in installations that have started operation before the entry into force of this Regulation, CO2 may be allocated to a part of the total output of the process provided the carbon capture rate for the part of the incorporated process does not surpass 100%. For all other installations the net emission savings must be proportionally allocated to the entire fuel output'*. According to Annex A.18, the same applies in the case of CCU.	In light of the potential risks linked to sizing the low-carbon hydrogen market the text should clarify how 'installations' are defined in this context. In particular, it should be specified whether the term refer exclusively to existing SMRs, or is it intended to cover a broader scope, including already installed CO_2 capture plants as well.

Default values (Annex B)		
Topic	***Low Carbon Delegated Regulation provision***	***Open questions***
Traceability of the natural gas	The Delegated Regulation breaks down natural gas between pipeline gas and LNG.	**(?)** Uncertainty on the approach that will be followed to **trace and distinguish natural gas**.

<table>
<tr><td>Transport emissions</td><td>Annex A.7 (c) establishes that transport emissions for fossil-based inputs shall be calculated based on Methane Regulation reporting.</td><td colspan="2">(?) The approach and acceptability of the data stemming from Methane Regulation remains to be explicated. In addition, it should be made clear how the Delegated Act would match the Methane Regulation implementation timeline and the potential situation where data is not (yet) available.</td></tr>
<tr><td>Pipeline gas</td><td>The text allows deviation from the default values for the methane emissions (CH_4) component. This will be possible by relying on the methodology under the Methane Regulation. The text also clarifies that until the Methane Regulation is not in place, other scientific method such as the OGMP 2.0 can be used as an alternative pathway (Annex A.7(b), footnote 8).</td><td colspan="2">(?) The text lacks guidance on what and how ‘other specific methods’ could apply.
(?) It is unclear how the low carbon fuels producer should approach a situation where they source the natural gas from multiple suppliers, some of whom provide specific methane emissions data while others do not. It should be better specified whether:
a) The producer can combine default values with project-specific ones,
b) If so, how the calculation should be made: by averaging values together, or by weighting them according to each supplier’s share of the total gas supply</td></tr>
<tr><td rowspan="3">LNG</td><td rowspan="3">The text establishes that GHG emissions shall be added to the emissions from pipeline gas to cover the liquefaction, shipping and regasification (Annex B).</td><td rowspan="2">For the CH_4 component, Annex B establishes that the reporting shall be done in accordance with Annex A.7 (provisions related to natural gas in general).</td><td>While the reference to the transport part of the value chain is explicit under Annex A.7 (despite the above), (?) there is no guidance for other parts of the value chain. Clarity should be provided in this regard.</td></tr>
<tr><td>The Methane Regulation cover yearly CH_4 emissions. (?) Misalignment between Methane Regulation annual CH_4 emissions reporting and hydrogen projects’ monthly reporting requirements. The European Commission should clarify how to ensure consistency between the rules.</td></tr>
<tr><td>For the CO_2 and N_2O components, there is no explanation nor referenced source for emissions reporting and what sources should be used.</td><td>(?) This should be clarified with the utmost urgence.</td></tr>
<tr><td>Definition of incorporated process</td><td>Natural gas is considered as an elastic input. If from an incorporated process,</td><td colspan="2">Despite amendments, (?) the definition of ‘incorporated process’ (footnote 6) remains unclear, requiring clarification from the European Commission. Are project-specific values for CO2 allowed in this case and under which methodology?</td></tr>
</table>

	LCF producers can deviate from each of the natural gas' Annex B default values (Annex A.7).	

Long-term structural revision

The inability for producers to demonstrate the better environmental performance of individual projects, particularly with regard to CO_2 emissions, is the key shortcoming of the Delegated Regulation. Under the current framework, economic operators are unable rely on actual or project-specific data. As a result, producers are required to rely on conservative default values that often fail to reflect real-world performance. This creates a significant market barrier, as many projects struggle to meet the 70% GHG emissions reduction threshold from the outset of the production process, even before accounting for emissions generated along the rest of the value chain. Any future revision of the Delegated Regulation must therefore address this issue as a matter of priority and allow the use of verified project-specific values where appropriate.

The Commission has already recognised the need for greater granularity in emissions accounting. Article 3 foresees an assessment, by 2028, of the introduction of country- or region-specific standard values in Annex B. While this would represent an improvement over the current approach, it would only partially address the underlying problem. The possibility to use project-specific values for upstream CO_2 emissions remains essential to accurately reflect the performance of individual installations and should therefore be incorporated into the framework.

In addition, **the EU legislative framework governing solid carbon should be revised to provide greater legal clarity and recognition for this valuable co-product of the methane pyrolysis process**. The current regulatory landscape remains fragmented and does not adequately reflect the contribution that solid carbon can make to decarbonisation objectives and to the broader emissions reductions in the solid carbon business[9]. In particular, the Delegated Regulation refers to:

- Delegated Regulation (EU) 2026/285 establishing certification methodologies for permanent carbon removals: in its current form, this framework does not recognise methane pyrolysis as an eligible and established production pathway for biochar. Eurogas has repeatedly raised this issue, which represents a missed opportunity to unlock additional emissions reductions and carbon management solutions in Europe.

- Delegated Regulation (EU) 2024/2620 which addresses permanent CCU applications: While relevant, this framework does not specifically cover solid carbon. Instead, it focuses primarily on CO_2 mineralisation pathways. Furthermore, the list of recognised permanent CCU applications remains

[9] For additional information around the potential and existing barriers to the solid carbon business case, please refer to Eurogas position paper on this topic.

narrowly defined and does not encompass a range of potential market applications for solid carbon, limiting the development and deployment of innovative carbon utilisation solutions.

Finally, **regulatory complexity and uncertainty continue to affect industrial processes involving multiple inputs and co-processing**. Indeed, the methodologies established under RED III, Delegated Regulations 2023/1184, 2024/1185 and 2025/2359 on emissions accounting do not provide a clear basis for calculating product fractions and their associated carbon footprint. These barriers in accounting methodologies should be swiftly lifted.

Eurogas considers that projects that have already taken FIDs should not be exposed to future regulatory changes that could undermine their business case. To this end, **grandfathering should be foreseen for all projects having taken FID based on the existing legal text**, to safeguard nascent projects from potential future restrictions under the Low-Carbon Delegated Act. This grandfathering should, however, not prevent early movers from capitalizing on any additional flexibilities introduced pursuant to Article 3 of this DA.

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