CONSULTATION RESPONSE

Energy Traders Europe response to the EU Commission consultation on the Delegated Act for low-carbon hydrogen under the recast Gas Directive

Brussels, 25 October 2024 – Energy Traders Europe appreciates the opportunity to provide our comments on the methodology for determining greenhouse gas (GHG) emissions of low carbon fuels (LCF), as consulted by the EU Commission under article 9 of Directive (EU) 2024/1788 (recast Gas Directive).

We broadly support the intention of the EU Commission to standardise a tradable product in low-carbon hydrogen based on the application of the overarching 70% GHG emission reduction threshold against the unabated fossil equivalent under Directive (EU) 2018/2001 (RED II), factoring in methane leakage and carbon capture measurements. We also welcome the technology neutrality principle in the application of the given threshold, irrespective of the technology used to produce low-carbon hydrogen.

To enable the standardisation of low-carbon gas certificates and their cross-border recognition, as well as the subsequent standardisation of contracts, our response seeks to ensure that the proposed Act is specific and clear enough to minimise transaction costs and administrative burden. Our detailed observations are built around the two key elements to be considered for a low-carbon hydrogen project to meet the 70% threshold:

1) Emissions from the natural gas supply chain and the CO_2 capture rate,
2) Emissions from power supply, in particular, but not limited to, the case of electrolytic production of hydrogen from non-renewable power.

1. General remarks

1.1 Basic principles for establishing a well-functioning traded market in low-carbon hydrogen in support of the energy transition

A well-functioning traded market in low-carbon hydrogen is needed to facilitate and speed up the energy transition. To establish such a market, the underlying product needs to be *robust*, i.e. it needs to document the environmental value in a manner that is standardised, credible and easy to understand by all market participants, particularly consumers. The product should be shipped and traded effectively, and the mass balancing set-up operated under the Union Database (UDB) can help achieve that. **We thus endorse the alignment, under preamble 4 of the draft Act, of the traceability scope for low-carbon gases through the Union database (UDB) with the corresponding framework under RED II and III for biofuels and biogases. Aligned traceability criteria will ensure that the market can develop, reaching a stage where a credible, transparent price signal for low-carbon hydrogen is established.**

Producers of low-carbon hydrogen and fuels must be allowed to opt for the source of gas or electricity of their choice and to report its underlying carbon footprint on this basis, provided traceability of the input can be ensured or certified. This would bring a market for natural gas emissions certificates in the long run[1], on top of existing renewable and low-carbon GoO or PoS products (the latter being encompassed into the upcoming UDB). For this, we caution against implementation of the traceability through the UDB of the batches of fuels/ raw material based on the methane performance profile of gas suppliers to low-carbon hydrogen producers, in analogy to the currently consulted extension of the traceability scope of the UDB to biomethane feedstocks[2].

1.2 The 70% GHG emissions reduction threshold must help standardise robust certification inside and outside the EU

Energy Traders Europe emphasises the need to attain a common, EU-wide approach for defining and certifying low-carbon hydrogen and fuels, with the 70% greenhouse gas (GHG) emissions reduction threshold compared to EF(t) under Annexes V, VI RED II and preamble 9 of Delegated Regulation (EU) 2023/1185 under RED II – i.e., 94gCO_2e/MJ- serving as the sole benchmark for achieving the low-carbon status. **This single threshold should apply to allow sufficient commonality of the product features and enable trading/ exchanges among decarbonised standard products of LCF against renewable fuels of non-biological origin (RFNBO) and biomethane in existing and future compliance markets.**

As hydrogen demand progressively develops subject to financial and regulatory incentives, EU-produced hydrogen and imported hydrogen should at least be compared, defined and certified on a

[1] To avoid de-commoditising the gas market we expect that identification of the source of gas would be assigned on an ex-post basis. Once consumed volumes are known, they can be matched with equivalent quantities of production / import / storage withdrawal (assuming such information can be obtained – significant challenges remain on how to identify the source of gas prior to acquisition by a supplier). Ex post certificate trading could be part of this.

[2] Renewable and recycled carbon fuels – extending the scope of traceability of the EU database

level playing field. The standard benchmark calculation under Annex A2 of the proposed Act is also important for prospective trade in low-carbon hydrogen with third countries and traceability of non-EU imported low-carbon hydrogen via the UDB, as is fortunately already provided for under article 9(4) of the recast Gas Directive.

Given the general provision under the Recast Gas Directive, as well as the applicability to non-EU producers of provisions under annex A7 regarding the default upstream values for natural gas in table 1 of annex B and the prospective methodologies under Regulation (EU) 2024/1787 (Methane Emissions Regulation – MER), we also urge the Commission to extend the notion of the single mass-balancing facility to all interconnected third-country grids and, therefore, the accessibility to the UDB to all economic operators active in interconnected third-country grids. This is important so that the current registration issues faced by non-EU economic operators[3] do not extend to LCF produced outside the EU, most notably the analogical approach of demonstrating a direct pipeline connection between a natural gas production well and an LCF production installation.

2. Detailed remarks

2.1 Emissions from the natural gas supply chain

2.1.1 Use of operator data for emission intensities must be allowed before August 2025 and cover the full natural gas value chain

Regarding the possibility of use of project-specific values, annex A7 refers to reliance on the methodologies under the MER, be it for EU operators under article 12 or for operators outside the EU under articles 27(1) and 28(1), (2) and (5) (kicking in as of August 2025), with both subsequently bound by the methane intensity methodology to be developed by the EU Commission by 05 August 2027. **We stress that this reference to the MER only applies to upstream production, and ask that:**

[3] As per the operational design of the UDB and EU Commission communications to economic operators from late 2023, gas withdrawn from third-country grids cannot be certified by voluntary schemes as biomethane. Nevertheless, biomethane coming from a direct pipeline connection with a biomethane plant can be certified, provided the certification verifies and guarantees that the amount of biomethane claimed and used in the further production of fuels can be effectively sourced, taking into consideration the technical capacity of the supplying biomethane plant and other supplies of that production plant to other economic operators.

A) The link between the MER and the draft Delegated Act is made **only after clear guidance has been provided by the EU Commission to Competent Authorities on possible certification systems of compliance with the requirements of the former**[4].

B) Low-carbon projects currently developed with **project-specific values** are allowed to use plant- or field-specific data for reporting to Competent Authorities **before EU operators' reporting under article 12 MER kicks in – i.e., before August 2025.**

C) To avoid delays for projects nearing final investment decision (FID), it is essential that, **until the methane intensity methodology is published for gas used as input to both EU and non-EU produced LCF under article 29(4) MER, operators are allowed to put forward methodologies for determining the upstream methane intensity for approval by authorities in their respective jurisdictions**[5]. These methodologies must remain valid only until implementation of the MER.

D) **Actual operator data** are allowed to be used to demonstrate methane emissions **also in other parts of the natural gas value chain, beyond production,** notably if operators can demonstrate better GHG performance on the gas that they use.

E) **Carbon dioxide data are also project-specific,** if possible to be demonstrated.

A mechanism is needed through which operators can provide actual data on or give a good indication of intensities for different pathways of supply sources of gas, having the option to make use of data

---

[4] For further reference, see our Energy Traders Europe remarks for the EU Commission on the MER importer obligations and letter to national authorities asking for the implementation of the MER not to lead to premature penalisation of obligated importers. We furthermore note that during the ad hoc MER workshops held on 15 and 17 October 2024, the EU Commission stated that there is no Implementing or Delegated Act mandating them to come up with a certification system of compliance based on the principle of mass balanced gas, as the one under the RED. The EU Commission also ruled out the possibility to provide guidance or opinions on potential systems of compliance with the requirements of MER. However, it stated that it might provide, informally, some guidance, to Member States, upon request of theirs or of their Competent Authorities.

[5] A practical way to implement a workable methodology would be to allow project developers to present verifiable GHG emissions allocated to the natural gas production converted to GHG emissions intensity. By utilising the existing ISO 14067 standard, this will ensure consistent methane emissions intensity approaches across producers for their individual feedstock supply.

from credible third-party data vendors that accurately reflects their specific GHG emissions. In the same way, capture rates from hydrogen production units such as steam methane reforming (SMR) and auto-thermal reforming (ATR) should always be project-specific to build trust in a robust product. **For this, we suggest that in annex A7 the first sentence in the second paragraph is changed to the text below:**

"GHG emissions from elastic inputs that are not obtained from an incorporated process may be determined based on the values included in Part B of this Annex. Projects can demonstrate better performance than default values (for CO_2, N_2O and CH_4 emissions) through actual values for project specific inputs."

By the same token, if a dedicated pipeline forming part of an incorporated process, as the latter is defined under annex A4, provides less than 50% of the input to LCF, the demonstration of certified operator values should be equally allowed.

2.1.2 Clear guidance must be given to operators on the use of default values for emission intensities until the MER kicks in

Admittedly, considering that methane intensity values may not be available in all cases, we appreciate the fact that the EU Commission is also providing the alternative to use, until the MER kicks in, the average value included in part B of the Annex.

Any potential review of the calculation methodology under annex B, in the context of the EU Commission review of article 9 recast Gas Directive under article 92 recast Gas Directive, risks impacting the rollout of long-term projects. The resulting value expressed as an average may be significantly higher than actual purchased natural gas, thus not incentivising efforts to produce and purchase natural gas with lower emission intensity.

Our understanding is that for elastic inputs, such as natural gas destined for SMR/ ATR to produce blue hydrogen with CCS, we should use the midstream and downstream GHG-eq. of the annexed upstream value augmented by 40% for the methane emission intensity component. **Considering that value is already higher than the corresponding one under the GHG Act, we seek more clarity as to whether this increase will be calculated per production site/ supply contract.**

2.1.3 Dedicated infrastructure

We ask for the "dedicated infrastructure" referenced under annex A4 to be defined not exclusively as a direct line between the source and the sink of the natural gas, but also allowing connection of others to the same pipeline.

2.1.4 Time basis

Under annex A1, GHG emissions must be calculated as an average for the entire production of low-carbon hydrogen monthly. This is a provision replicated from annex A1 Delegated Regulation (EU) 2023/1185. Considering the use of natural gas as feedstock for LCF production, we ask for the possibility to use average annual data for methane feedstocks to ensure consistency with the MER requirements.

2.2 Emissions from the power supply

2.2.1 Carbon intensity of power processing must be acknowledged along the hydrogen value chain, potentially including through PPAs

While the production of hydrogen is still limited, the growing demand, at least in the short- to medium-term, cannot be covered by renewable hydrogen alone. For the same reason, different ways to produce renewable and low-carbon hydrogen will need to coexist. In addition, stable and controllable production of low-carbon hydrogen would allow accommodating for short-term and seasonal demand fluctuations. No matter its production method, stable, baseload production of hydrogen would help cater for the demand profiles of consumers, underpinning the developing of the new market.

To enable maximum emission savings in the hydrogen value chain, all power sourcing options which can reduce the carbon intensity footprint of a fuel should be allowed. We acknowledge the intention, under annex A6 of the draft Delegated Act, for the listed rules on grid-sourced electricity to cover different pathways for allocation of low-emission power to low carbon hydrogen producers.

We encourage the EU Commission to explore ahead of 2028 if power purchase agreements (PPAs) for non-fully renewable electricity[6] could be an additional option for

---

[6] E.g., nuclear power from nuclear sources, existing renewable energy assets (e.g., hydro), as well as biomass-based power plants.

producing electrolysed low carbon hydrogen[7]. The same option should be considered for powering energy intense value chains (e.g., ammonia), for powering the manufacturing process of a low carbon fuel plant (e.g. ATR/ SMR, air separation unit, CO_2 compression etc.), as well as processes related to the actual sourcing of hydrogen molecules in the EU gas grid (e.g., compression, storages and other ancillary services.) Such an option should, however, not lead to potential double counting of low carbon electricity production if combined with the existing draft electricity rules for low carbon hydrogen.

2.2.2 We welcome the prospective introduction of more precise hourly carbon intensity values

We welcome the idea put forward by this draft to use hourly grid CI values to demonstrate the CI impact of electricity in the production of hydrogen when sourcing power from the grid without a PPA.

In our view, this option should be introduced without delay. Article 20a of Directive (EU) 2023/2413 requires Member States to ensure that transmission system operators (TSOs) publish the share of renewable electricity and GHG emissions content of electricity supplied in each bidding zone at (minimum) hourly intervals. Given that this data is already collected, and forecasts are made, TSOs should make it available to demonstrate the specific CI of grid electricity in any given hour to accurately reflect it in the carbon intensity of outputs.

If these changes are made, to ensure that consistency is maintained and carbon intensity savings along the value chain are rewarded, they also need to be recognised under the RFNBO Delegated Acts.

2.2.3 Comments on the rules for grid-sourced low-carbon electricity

Regarding annex A6 (A), we ask for clarity on the exact elements entailed in the assessment of the carbon intensity of the grid of Member States under annex C, including whether the TSO control area or bidding zones are taken into account, the type of electricity plants and the exact time period measured. Moreover, it is unclear how the carbon intensity would be calculated for countries outside of the EU (e.g., in the US, where the electricity market design is different – nodal model -, thus bidding zones do not exist). The EU Commission should set out clear guidance for countries outside

---

[7] We consider that, as per previous EU Commission clarifications, grid-connected electrolysers may supplement RFNBO production in a given hour/ month with non-fully renewable electricity.

of the EU on how these rules are expected to be met (i.e. equivalence to an EU bidding zone) and what default values need to be used.

Regarding annex A6 (B), we understand that the threshold of 183 g CO2eq/MJ must be accounted for every extra hour of operation of an electrolyser. This risks leading to a considerable decrease in the number of operation hours and, consequently, of the LCF share.

Regarding annex A6 (C), we point to the complexity entailed in the use of the day-ahead market results to determine the marginal plant, although it can be assumed that a RES-E plant sets the price based on low day-ahead prices between a low-price and a high-price bidding zone.

As a broader note on annex A5 of the draft Act which replicates the RFNBO rules, we would like to re-iterate our concerns, previously shared with the EU Commission, regarding restrictions on intermediaries in PPA structures introduced in subsequent interpretative Guidance notes on the RFNBO Delegated Act. In most PPA structures, neither the generator nor the electrolyser operator can take the imbalance risk.

Even in a sleeving structure where there is a direct PPA between the generator and the electrolyser, there still is another entity sitting in the middle to deal with the balancing, as well as with the respective nominations. All corporate PPA scenarios will always come with some form of sleeving (i.e., indirect) structure, supplementing a direct PPA. **To facilitate commercial negotiations, we ask that next iterations of the RFNBO Guidance stick to the definition of PPAs under article 2(17) RED II without further detailing permutations of PPA structures, as these exist in various forms in the market and are a matter of commercial arrangements.**

Finally, particularly regarding question 20 of the second iteration of this Guidance[8], we stress that the GoOs should normally be allowed to go through the intermediary as PPA contracting party in line with article 5 of the RFNBO Delegated Act, before they (and the electricity) reach the end-user. By disabling that, the power generation profile risk is hard to manage, as not all renewable power producers are large companies with well distributed and diversified generation and/or already integrated in trading companies. They would thus not always be able to offer a predefined profile and/ or take the balancing risk. Correspondingly, hydrogen producers will need stable power flow to ensure electrolyser operations.

[8] Q&A implementation of hydrogen delegated acts – version of 14/03/2024

3. Concluding remarks – grandfathering asks

In line with the RFNBO DA, and in view of the regulatory uncertainty driven by still unclear but incoming regulations mostly pertinent to natural gas, we ask for the introduction of a grandfathering clause. Such a clause would give comfort to investors and thus support the development of a full-fledged traded market in low-carbon hydrogen. **As is the case with RFNBO installations, we find that grandfathering should be implemented for a 10-year period for LCF installations commissioned before 2030 and covering the period from commissioning date to 2040.** The grandfathering should cover the events listed below:

A) The fossil fuel comparator from the GHG Delegated Act should be used as a reference for low-carbon fuels, meaning that a parallel review of the RFNBO DAs – planned for 2028 – should not change the Gas Directive-determined fossil fuel comparator.

B) Accordingly, potential review of article 9 recast Gas Directive, as foreseen under article 92, should not affect the 70% GHG savings threshold for plants commissioned (rather than start operation) before the end of 2030.

C) Once mature scientific evidence suffices to that end, the introduction of a global warming potential for hydrogen leakages into the GHG emissions calculation for low-carbon fuels should not apply to projects commissioned before the introduction of the value.

D) Facilities commissioned outside the EU and supplying the EU market should be allowed the same grandfathering as facilities within the EU.

Contact

Mariana Liakopoulou
Markets and Policy Associate
M.Liakopoulou@energytraderseurope.org