Hydrogen Europe

Hydrogen Europe Consultation Response

Draft Delegated Regulation on GHG calculation methodology for RFNBO and RCF

June 2022

The Delegated Regulation on establishing a minimum threshold for greenhouse gas emissions savings of recycled carbon fuels (RCF) and specifying a methodology for assessing greenhouse gas emissions savings from renewable liquid and gaseous transport fuels of non-biological origin (RFNBO) and from recycled carbon fuels together with its relevant annex (henceforth: "**DA**") is an important regulation, which can have a profound impact on the number of investment decisions for projects aiming the production of said fuels. It will also have serious implications on the final cost.

As such, Hydrogen Europe welcomes the DA as a timely initiative, which introduces much-needed regulatory clarity. Yet, in order for the regulation to benefit the development of recycled carbon fuels and RFNBOs, we identified several points that could be improved.

Flexible GHG allocation (Annex, Part A, Point 1 and Point 15f)

The DA specifies very rigid rules for the allocation of emissions, i.e. if a fuel is a mix of RFNBO and RCF and other types of fuels, all fuel types shall be considered to have the same emission intensity (Part A, Point 1). In addition, if there are other co-products – which are not used as fuels - the allocation shall be done by the economic value of the co-products. This creates a number of potential problems:

A. This allocation method makes it impossible to meet the GHG emission threshold without starting from 70+% renewable energy input from day one. Therefore, this approach puts at a disadvantage existing fuel synthesis plants which might want to gradually increase the renewable energy input to the process, responding to the gradually growing demand for RFNBO and RCF.
B. Furthermore, the economic value of an input/output has high volatility and could change in a short matter of time which leads to uncertainty about the determination of input/output type. This is especially problematic since the GHG intensity of fuels will in many cases also be calculated on an hourly basis. This is due to the hourly temporal correlation envisaged in the Delegated Regulation on the methodology setting out the rules for RFNBOs production..

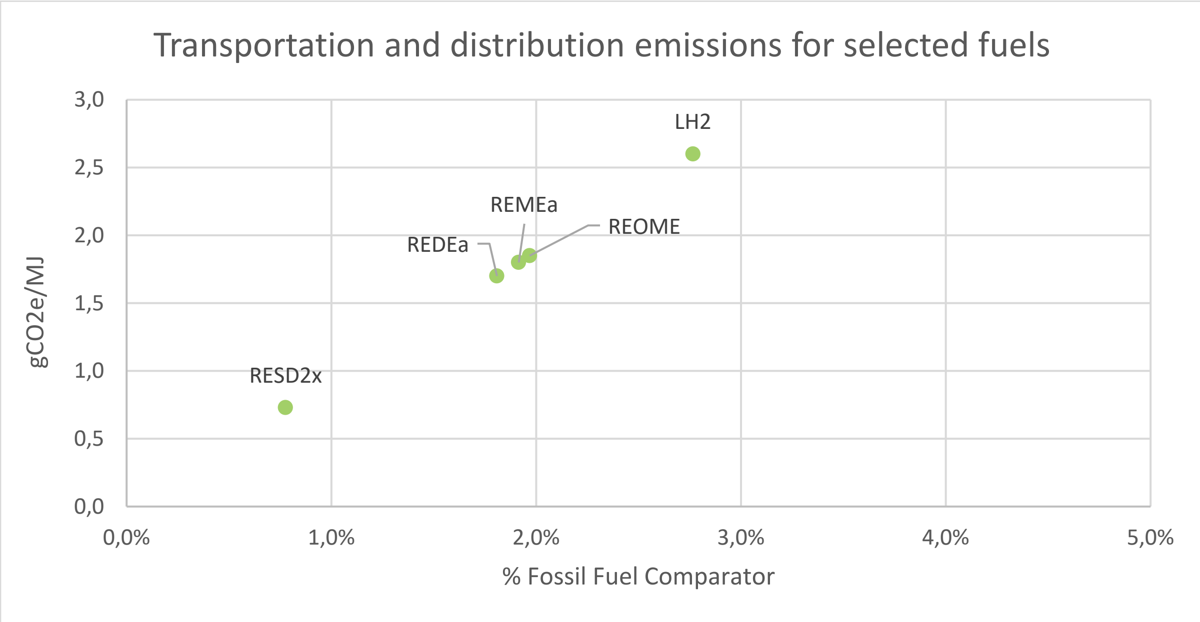
Recommendation 1: We recommend allowing a flexible GHG allocation methodology, recognising the allocation of greenhouse gas (GHG) benefits to a specified product or product line in Fischer-Tropsch (or other fuel synthesis) facilities co-processing fossil fuel and sustainable inputs. Flexible allocation methodologies are recognised by global certification bodies, including the Roundtable on Sustainable Biomaterials (RSB) and the International Sustainability and Carbon Certification (ISCC).

In order to avoid the creation of a potential loophole in the system, the flexible allocation should be limited so that the fuel producer doesn't allocate a higher emissions intensity to one of the products than that of the fossil benchmark. At the very least the rule regarding the allocation based on economic value should be changed from "the average factory-gate value of the products over the last three years" to "the average factory-gate value of the products over the last three **full calendar** years".

Emissions from fuel transportation, storage and distribution (Annex, Part A, Point 1)

According to the suggested methodology, emissions from transport and distribution shall include emissions from the storage and distribution of the finished fuels. However, distribution and storage can be long-term processes with hydrogen market development and these processes can take place after the transfer of ownership of the fuels to the trader. This means that the results of RFNBO certification will depend on distribution efficiency and the duration of storage. Both of these can and often will be outside of the responsibility of the fuel producer.

Furthermore, emissions from fuel storage and distribution are relatively small compared to the fossil fuel comparator (**FFC**). As the recent JEC WTT study 5.0 shows, for e-fuels these emissions are usually below 2 gCO2e/MJ, i.e. below 2% of the FFC, while for liquefied hydrogen those emissions account for around 3% of FFC.



Source: JEC WTT Study 5.0.

Note: LH2 – liquefied hydrogen transported by trucks and cryo-compressed at dispensing station, REMEa - Renewable electricity to methanol; REDEa - Renewable electricity to DME; RESD2x - Renewable electricity to Syndiesel; REOME - Renewable electricity to oxymethylene ether (OME).

It is therefore not clear why is it necessary to include these emissions at all, given the difficulty of doing it accurately, having in mind the likely change of ownership of the fuel at that stage.

Recommendation 2: We suggest removing the transport and distribution emissions from the equation in Part A, point 1 of the Annex for all fuels in the same way as for compressed hydrogen, considering the relatively low emissions. This will also help reduce the administrative burden of the DA.

Distinction between rigid and elastic inputs (Annex, Part A, Point 4)

We support the proposal on making no distinction between the three types of inputs (rigid/semi-elastic/elastic). However, we highlight that the definitions of rigid and elastic inputs/outputs need to be clearer, as current descriptions are lacking detail.

Furthermore, we would welcome a non-exhaustive list of examples as we see a risk of the status of CO2 sources (whether they are elastic or rigid) changing over time, e.g. as a result of a market for captured carbon (or if ETS prices were to increase significantly). This can make it very difficult to both navigate the definitions and invest in projects using a specific source.

Recommendation 3: We suggest clarifying the definitions for rigid and elastic inputs and outputs, and provide a list of examples to avoid confusion.

The methodology for assigning GHG emissions to electricity taken from the grid which is not fully renewable (Annex, Part A, Points 6 - 8)

We welcome the possibility of assigning zero GHG emission intensity to grid electricity that is not fully renewable if it can be reasonably assessed that the merit order was closed by renewable energy or nuclear energy. However, **we recommend that the average from the last 2 years should be used instead of the previous year only**. This would smoothen the progression and create needed visibility and stability to stakeholders. It should also be clarified how should energy imports be treated when they set the marginal price in the country.

Furthermore, we would like to point out that there are other low emission generation sources like CCS/U power plants and installations using by-product hydrogen as fuel, in addition to nuclear and renewable energy sources. This is somewhat addressed in point 7 of Part A of the Annex, which proposes an alternative method for the allocation of emissions to grid electricity. According to the text, the GHG emission value of the marginal unit generating electricity at the time of the RFNBO production in the bidding zone may be used, if such information is publicly available from a reliable source.

Yet, using the marginal unit generating electricity at the time as the reference will lead to inaccuracies – especially if there are multiple power-to-gas installations producing hydrogen at that time. Assigning the emissions of the marginal source to all of those installations may lead to an unjustified overestimation of emissions.

Recommendation 4: We recommend that fuel producers should be allowed to use the emissions of the hourly average electricity mix in the bidding zone provided by the TSO or other publicly available reliable data as an alternative to using average grid carbon intensity provided in Part C. This would incentivise electrolysers to be turned off during hours of highest carbon intensity. We also believe that this is a more accurate approach.

Point 6 of the Annex provides an option to assign a GHG intensity value to the electricity taken from the grid that does not qualify as fully renewable. This depends on the number of the full load hours (FLH) of the installation producing RFNBOs and RCFs is operating with respect to the number of hours (h) in which the marginal price of electricity was set by the installations producing renewable electricity or nuclear power plants in the preceding calendar year for which reliable data are available.

While the case in which FLH<h is clear, it is unclear in the case in which FLH>h. The DA states that *"Where this number of full load hours is exceeded, grid electricity used in the production process of renewable liquid and gaseous transport fuels of non-biological origin and recycled carbon fuels shall be attributed a greenhouse gas emissions value of 183 g CO2eq/MJ".*

Recommendation 5*:* We suggest making it explicit that in the case of FLH>h, a GHG emissions value of 183 g CO2eq/MJ shall be attributed only to the extra number of full load hours exceeding the number of hours in which the marginal price of electricity was set by RES or nuclear power plants (i.e. FLH - h) and not to all FLH. Furthermore, it should be made clear that these hours come on top of the number of hours where the installation producing RFNBOs is producing RFNBOs by drawing on electricity counting as fully renewable. This provision should not be used to limit the total maximum number of hours that a

RFNBO producer can operate to the total number of hours where the marginal price was set by RES and nuclear.

Recommendation 6: It should be made explicit that fuel producers can combine two different sources of electricity at any given time, provided the average GHG emission intensity of fuels produced during the same period is still low enough to meet the 70% emission reduction target. Excluding such an option would have a significant negative effect on hydrogen production profitability. An onshore wind park with a capacity factor of 2,000 full load hours will still produce some electricity for more than 6000-7000 hours per year (albeit not at full capacity), making it impossible to increase the electrolyser utilization even at times when the marginal generation source in the grid is renewable.

Increase the accuracy of GHG emissions of elastic inputs (Annex, Part A, Point 10, Part B and Part C)

The methodology introduces several ”standard values” for the GHG intensities of elastic inputs, including electricity. Yet, this contains several errors and inaccuracies, including:

- The standard emission values for lignite seem mixed-up. The table in Part B with GHG intensities of inputs other than electricity, suggest a total emissions value for lignite of 1.7 gCO2eq/MJ, while upstream emissions are 115.0 gCO2eq/MJ.
- The standard value for upstream emissions for natural gas provided in Part B is 9.7 gCO2eq/MJ. This seems accurate for natural gas imported from Russia but significantly overestimates upstream emissions of natural gas supplied from the Netherlands or Norway.
- The table in Part C is outdated. It should be made clear that producers can use data from the preceding year – if available.
- In Part C the text claims that “The emissions from the construction and decommissioning and waste management of electricity producing facilities are not considered”. If so however, the emissions from nuclear power provided in table 3 for the upstream emission factor for nuclear electricity (1.4 gCO2/MJ) seems largely overestimated and can only be explained if emissions from the plant construction and decommissioning were in fact included (no explicit reference to this figure can be found in the JRC JEC Well-to wheel report v5). A more robust expert reference is the JRC publication with a specific focus on nuclear energy[1]. Based on this JRC analysis, we recommend replacing the upstream emission factor of 1.4 gCO2/MJ for nuclear in table 3 by 0.29 gCO2/MJ for primary heat produced which corresponds to 0.88 gCO2/MJ for final electricity produced.

Recommendation 7: Amend the values associated with lignite emissions and consider changes for natural gas and nuclear upstream emissions.

Double counting of CO2 from previous or alternative use (Annex, Part A, Point 10)

Emissions from the diversion of hydrogen (or other by-products) from previous or alternative use shouldn't be attributed to hydrogen as this might lead to the double counting of CO2 emissions. For example, if the current use of hydrogen would be power generation, when that hydrogen would be

[1] JRC Science for policy report, Technical assessment of nuclear energy with respect to the ‘Do no significant harm’ criteria of Regulation (EU) 2020/852 (Taxonomy Regulation), 2021.

redirected for RFNBO or RCF production, the previously generated power would indeed have to be replaced by other electricity sources. Yet – whatever the additional emissions would be, those emissions would be accounted for already in the ETS system for power generation. As such, if this would result in additional CO2 emissions, their cost would be borne by the electricity end users. There is no reason to assign these CO2 emissions for the second time to RFNBO or RCF.

Recommendation 8: More flexibility should be allowed as a bare minimum. Instead of rigid rules forcing RFNBO/RCF producers to allocate emissions based on predefined emission factors (e.g. average GHG intensity of grid electricity generation in the country where the displacement occurred), **it should be possible to use actual emissions**. For example, if the fuel manufacturer could prove that the displaced electricity was replaced with a PPA with a renewable energy source, he/she should be allowed to assign no emissions as a result of the diversion of the product from its current use. This would create an incentive to replace the redirected energy or fuels with renewable or low carbon equivalents.

Recommendation 9: Point 10.3. should be deleted entirely. In addition to similar CO2 double-counting issues, it would also attribute entirely theoretical GHG emissions to RFNBO/RCF. We firmly support the LCA approach which would hold fuel manufacturers fully accountable for all the emissions they generate along the entire supply chain. However, we are deeply concerned about burdening producers with emissions generated by third parties solely because those could have been potentially avoided if the said fuel manufacturers would make a different investment decision.

Origin of sustainable CO2 (Annex, Part A, Point 11)

Meeting the proposed ReFuelEU Aviation targets of 2% of SAF in 2025 and 63% in 2050 and the proposed increased RFNBO target in transport will require significant amounts of CO2.

While Hydrogen Europe fully supports the exclusion of CO2 from unsustainable sources, the proposed approach is too restrictive and will result in an insufficient supply of affordable CO2. This in turn will decrease political support for the proposed targets rendering them unachievable.

In addition, we consider the current approach is overly restrictive because given the long lead times for investment on carbon capture (CC) solutions, a transition period ending at the beginning of 2036 will effectively limit the CC facility lifetime to 10 years or less, which is insufficient to provide the necessary investment incentive.

Recommendation 10: We suggest that a grandfathering rule should be introduced allowing all installations which enter operation before the end of the transitional phase, to continue operation indefinitely.

We also note that all the emissions covered by the ETS are not of the same nature. While some are avoidable, others are unavoidable.

Recommendation 11: The Commission should therefore provide a clear, rule-based definition of “unsustainable processes”. We consider the scope of the definition should not include ‘unavoidable’ CO2 emissions, which should be considered as sustainable. The category of ‘unavoidable’ CO2 emissions should as a bare minimum include the following CO2 sources:

- Waste incineration
- Manufacturing of cement
- CO_2 Emissions from the RFNBO/RCF fuel synthesis itself.

Covering the cost of CO_2 (Annex, Part A, Point 11)

The DA proposes that the costs of the CO_2 captured from ETS installations to include the full EU ETS costs and to be included in the final e-fuel costs. This creates a disadvantage compared to biofuels (exempted from the ETS). In addition, this will lead to double-counting of CO_2 with regard to the Aviation ETS. While emissions for biofuels are considered as zero in the Aviation ETS system, other fuels' emissions are calculated on the basis of the IPCC Guidelines. Yet, those guidelines include only fossil-based aviation gasoline or jet kerosene. Therefore, in the e-kerosene case, the CO_2 cost would have to be paid twice - once by the fuel producer and then again by the airline.

Recommendation 12: In order to avoid the double payment of CO_2 for aviation uses, the Directive 2003/87/EC should be amended accordingly to allow other emission factors to be used. These should be based on LCA methodology (in a similar way to the FuelEU Maritime) or free allowances should be awarded for airlines using e-fuels.

Hydrogen Europe

H2ero Net Zero

Propelling global carbon neutrality by accelerating the European hydrogen industry

Avenue de la Toison d'or 56-60
BE-1060 Brussels
+32 2 540 87 75

www.hydrogeneurope.eu

secretariat@hydrogeneurope.eu

@h2europe

Hydrogen Europe

@H2Europe