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Position Paper

Public Consultation on the revision of biofuel, bioliquid and biomass fuel production pathway values and modifying methodology

Review of Annexes V and VI according to Article 31(5) of the Renewable Energy Directive

Version: 1.3

Contents

1 Introduction

The draft Annex VI is of considerable interest to biogas and biomethane producers. The specific GHG emissions of our products determine both their market access and their competitiveness within individual markets.

It is therefore important to have a clearly understandable and easily implementable methodology that offers transparency, security and reliability to all stakeholders, such as voluntary systems, auditors, authorities and market participants. Against this background, we have the following questions and comments, which we kindly ask you to consider before implementing the new Annex VI:

2 Comments in detail

2.1 Default values

The presentation of default values across the entire production chain is a suitable tool for determining specific emissions. We expressly welcome the introduction of additional standard values for sewage sludge and the opening up of values for more fruit types compared to silage maize. In order to make better use of this tool, the following adjustments should be considered:

a) More substrates or substrate groups should be included (arable grass, permanent grassland, agricultural residues such as cereal and maize straw). The default value for silage, for example, must also include rye as a crop type. The default value for biowaste should also include agricultural residues such as straw and other crop residues.

b) The feeding of biogas plants is very flexible and, ideally, will always adapt to locally and temporally varying (waste) material flows. It is therefore virtually impossible to provide a definitive list of standard values. We therefore recommend a standard value for a 'worst performing feedstock' for renewable raw materials, waste and agricultural residues. This means that RED-compliant verification can be carried out using standard values in all cases, even without individual accounting.

c) The paragraph on compression and liquefaction emissions is extremely unclear and difficult to apply in practice. It should be reworded to indicate that the new value of compression emissions is considered 2.4g CO_2 while the liquefaction emissions for the EU-based liquefiers (on-site liquefaction or grid-connected liquefaction) can be defined based on the actual values, in particular, related to the electricity consumption and the CI of electricity grids, or the default value of 4.9g CO2.

d) The introduction of emissions from transport (especially for initial transport) is not entirely comprehensible from a technical point of view. We recommend that, for manure, the initial transport should not be subject to transport emissions if it does not exceed a reasonable distance of 25 km, as these emissions would also occur if the manure were used in arable farming.

e) The structure of the tables is not entirely logical. For example, adding up the emissions from the individual process steps and the possible credits does not result in the total values shown further on. It is therefore not transparent how the specific GHG emissions required by individual markets are achieved using standard values.

f) The application of the C_{stor} value for biomass for the production of gaseous energy sources is unclear. In changes to Annex VI, the EC has proposed a new C_{stor} factor (the correction factor reflecting the preservation of lower heating value of feedstock delivered at the gate) that should be applied to the emissions calculation formula. It is unclear if this factor was meant to be applicable only to solid (woody) biomass fuels or to all types of biomass fuels, including biomethane. In case it should be applicable to biomethane, an additional explanation and guidelines on how to calculate it in practice will be necessary.

2.2 Changeover from distinguishing between standard values according to technological options (energy supply, covering of fermentation residue storage facilities and exhaust gas after-treatment) to standard and best practice values

The change in the previous methodology (cases involving biogas CHP and biomethane) entails considerable uncertainties:

a) It is not clear whether the new default and typical values for biomethane are applicable exclusively in cases where the biomethane production process is fuelled by the own biogas and biomethane (we refer to this asterisk in the respective tables '*all settings assume that process energy is supplied from own biogas/biomethane production. Other practices should be calculated with actual values or default values)'. This will cause unintended negative impacts on the business case of biomethane by limiting the volumes that can be injected into the gas grid.

   Clarification is required as to whether other renewable energy solutions can be used on site of biogas/ biomethane production, thereby allowing the use of default and typical values. We recommend the following adjustment to the current wording (p. 37 of the ANNEX): "(*) all settings assume that process energy is supplied from documented renewable energy own biogas/biomethane. Other solutions should be calculated with actual values."

The argument for including such an adjustment is the need for broadening the scope of viable renewable sources of energy for the purpose of process energy and industrial processes. The European Union and Member States face a need to diversify its energy mix and sources of energy, including the need for further electrification of industrial processes where e.g. biomethane and/or biogas can be substituted with other relevant sources of renewable energy.

b) If the internal energy is not generated entirely from the BGA, it is no longer possible to use the complete standard value. Biomethane upgrading plants lack the technical capability to operate continuously on self-supplied electricity. We would like to highlight that the same issue applies to electricity generation from biogas. Using the standard "electricity from biogas" does not reflect real operational conditions, because biogas CHP units in Germany are no longer run continuously. Instead, they are operated in a highly flexible and demand-oriented manner. Their production follows periods of low electricity availability from wind and solar power, or times of high market prices. New biogas CHP units, for example, are typically supported for no more than 3,000 full-load hours per year. Continuous baseload electricity production for self-supply is therefore the exception rather than the rule.

   For this reason, we strongly request reinstating "electricity from the grid" as the applicable default standard. This would reflect actual operational practice and avoid systematically misrepresenting the carbon footprint of biogas-based electricity generation. We continue to recommend changing the method so that, in the absence of evidence of emission reduction measures (e.g. exhaust gas after-treatment, covering of fermentation residue storage), methane emissions are added at specific locations, e.g. (e_p).

c) The individual options in the table ('Sources of methane leakages') need to be better defined. For example, it is unclear why 'any technology' receives a higher credit for exhaust gas aftertreatment than a technology that is certified to reduce methane slip to below 0.2%.

2.3 Co-Digestion

We think that the feedstock-specific carbon intensity (CI) methodology for co-digested biomethane will be more suitable for the current and future set-up of regulated markets in the EU which are mainly based on the GHG emissions savings calculation of biofuels rather than energy content and which therefore incentivize consumption of biofuels with high emissions savings and sustainably produced from biowaste and residues (as follows from RED III, FEUM implementation process, REPowerEU and national policies).

We understand the Commission's view that a biogas plant is a single process with one average emission value. However, this approach does not reflect the market realities in Germany. Since German biomethane producers **receive no production subsidies**, their ability to allocate GHG emissions **per feedstock batch** is essential. Only through this "fractional allocation" can they offer differentiated products that meet customer expectations in a highly fragmented market.

Without feedstock-specific GHG values, many products – for example a maize-based batch – would no longer be marketable, even though they are fully compliant and sustainable. For German biomethane producers, the option to assign separate emission values to different feedstock batches is not a commercial preference, but the **foundation of our marketing and competitiveness**. It enables fair competition and ensures that unsubsidised producers in Germany can continue supplying the products demanded by industry, transport and utilities.

Therefore, maintaining the possibility of feedstock-based GHG allocation is essential for the functioning of the German biomethane market and for supporting decarbonisation in sectors that rely on these tailored products.

If the averaging methodology remains the policy choice of the EC, we suggest clarifying that 1) the share of raw materials fed into the digestor (Sn value) can be defined on the quarterly or monthly basis to align with the mass balance period of CI calculation; 2) that sustainability declarations for produced biogas and biomethane shall provide a single average CI value while specification of the Sn value calculation shall be provided by the biogas and biomethane producers to their auditors only.

Proposal to improve the rules on co-digestion

(Annex VI: (2) (ba) & (3) (c))

Necessity of substrate-specific allocation of emissions in co-digestion

Article 30 of RED III stipulates the application of a mass balance system for all economic operators. Through the proper application of a mass balance system, the sustainability characteristics and information on greenhouse gas emissions of input materials are retained throughout a process (e.g. processing, mixing or transport). Following the process, these characteristics are clearly assigned to the products.

Preserving substrate-specific GHG properties is necessary for various reasons:

- Biogas and biomethane producers can offer their products most efficiently in different markets, as the added value of sustainability and GHG properties varies between markets. This promotes the use of renewable fuels and takes all emissions fully into account.

- Separate marketing of biogas and biomethane products with different GHG values also increases the incentive for co-digestion plants to use more manure. Only particularly high negative emissions, such as those from manure, offer economic added value. With a low total value, additional improvement does not usually generate additional revenue.

Co-digestion plants can use various renewable substrates. This allows them to operate efficiently and utilise the biomass available in the region without having to rely on additional transport routes. If co-digestion plants are unable to allocate GHG emissions to specific substrates, they are at a disadvantage compared to mono-digestion plants, and additional transport routes would be promoted.

The current wording in the draft of Annex VI in points (2) (ba) and (3) (c) implies that in the case of co-digestion in biogas plants, GHG emissions are determined as a weighted average across all input substrates. However, this would mean that the specific GHG properties of the biomass used would be lost in this total value.

Another problem with the calculation formula is that the total value is to be calculated at plant level. In practice, however, it is much more practical to calculate it at product level. Annex VI states in various places that different emissions must be considered depending on the end product. In the operational practice of a co-fermentation plant, different products are manufactured which can generate different emissions in their production paths. For example, biogas is produced simultaneously for the generation of electricity and heat in the CHP plant at the site, as well as biomethane, which is fed into the gas grid as fuel for the heating market, and biomethane for the transport sector, part of which is then compressed as CNG and part of which is liquefied.

The calculation formulas presented in Annex VI, points (2) (ab) and (3) (c), do not reflect the fact that these emissions only occur with certain products. Furthermore, the corresponding emissions should only be allocated to the products with which they occur. For the calculation formula in (3) (c) to be technically correct, in addition to the index ‘n’ for the substrates, a further index ‘m’ for the respective starting products should be introduced. This refers to all emissions that occur after the production of the raw biogas, as these can vary depending on the product.

If emissions are aggregated across all products, biomethane for the transport sector, for example, is disadvantaged by methane and nitrous oxide emissions from power generation if a CHP plant is operated at the same site. However, as these emissions only occur in later process steps, it is already common practice to calculate emissions only for the respective products. Furthermore, in practice, the manufacturer often cannot know whether the biomethane will subsequently be compressed or liquefied by the buyer. However, the formula presented would require them to take these emissions into account when calculating the total value.

In addition to being able to calculate substrate-specific emission values, producers should also be given the option of aggregating the emissions for their biomethane products. For example, a producer can specifically calculate the actual emissions of its biomethane, which enters the transport market as a biofuel in the form of CNG. The choice between the two options gives producers the flexibility they need to optimally place their biomethane products on the respective markets. It should be possible to define the products both in terms of their product-specific GHG emissions and other sustainability and GHG reduction characteristics to tailor them to the respective market requirements.

Recommendation to amend the proposed legislation

Annex VI, point (3)(c) should be amended as follows:

In the case of co-digestion in the production of biogas and biomethane, the actual emissions of the biomethane or biogas product 'm' from the substrate 'n' are calculated using the formula:

$$E_{n,m} = e_{ec,n} + e_{td,feedstock,\,n} + e_{l,n} - e_{sca,n} + e_{p,n,m} + e_{td,product,n,m} + e_{u,n,m} - e_{ccs,n,m} - e_{ccr,n,m} + e_{me,n,m}$$

with:

$E_{n,\,m}$ = Emissions of biogas or biomethane from substrate n in product m.

The emissions for a product 'm' can be aggregated using the formula:

$$E_m = \sum_n (S_{n,\,m} * E_{n,\,m})$$

with:

E_m = Emissions of biogas or biomethane in the product m

$S_{n,\,m}$ = Energy content of biogas or biomethane from substrate n in product m.

The emissions of the entire plant can be aggregated using one of the following formulas:

$$E = \sum_n \sum_m (S_{n,\,m} * E_{n,\,m})$$

$$E = \sum_m (S_m * E_m)$$

with:

S_m = Proportion of the energy input in the product m in the total energy input.

The producer of biomethane/biogas must decide whether to determine the actual emissions for each product 'm' from substrate 'n' individually, or whether to aggregate them at product or plant level. Products can be defined both by their product-specific GHG emissions and by other sustainability and GHG reduction characteristics. It would also be useful to be able to set the S_N factor on a monthly or quarterly basis rather than just once a year, as currently described in Annex VI.

(Examples of products for which GHG emissions can be aggregated include bio-CNG from manure for the transport sector, bio-CNG from advanced biofuels, biomethane as fuel in the natural gas network from waste materials with GHG emissions below 10g CO_2/MJ)

2.4 Emissions from the liquefaction of biomethane

We welcome the introduction of a standard value for biomethane liquefaction within the EU. At the same time, it is important to ensure that this approach reflects the specific conditions of different business cases.

Germany has already invested in liquefaction facilities (grid liquefaction and on-site liquefaction) that operate independently of LNG imports and LNG terminals. These installations strengthen Germany's role as a key energy and technology location and enhance the resilience of energy supply. Creating a level playing field is therefore in the interest of all market participants and, ultimately, of customers.

The calculation of emissions should always refer to "normal" standard conditions, as defined in the Network Code on Interoperability and Data Exchange Rules (at least 0 °C).

We support the possibility to use actual values instead of default values.

2.5 New Fossil Fuel Comparator for Biomethane (Annex VI, N° 19)

A fossil fuel comparator of 94 g CO_2eq/MJ has been added in two occasions for biomethane injected into the gas grid for the purposes of the calculation referred to in point 3. We welcome the proposal that for biomethane injected in the gas grid and subsequently used as transport fuel the same fossil fuel comparator shall be applied as for all other (solid and gaseous) biomass fuels for transport and for (liquid) biofuels.

However, clarification is needed on the rationale for applying this new fossil fuel comparator for bio-methane used to produce electricity whereas for the production of useful heat the currently applicable approach is kept. We understand the potential benefits for the incorporation of the single fossil fuel comparator (FFC) for grid-injected biomethane at the level of 94g (CO_2)/MJ (fuel) but suggest clarifying the text to remove ambiguity caused by co-existence of this comparator with other fossil fuel comparators applicable to biomass fuels in general.

The newly introduced fossil fuel comparator of 94 g CO_2eq/MJ for biomethane can have negative consequences on electricity generation that currently benefits from a value of 183 g

CO_2eq/MJ, therefore disincentivising biomethane use in both electricity only generation and combined heat and power generation.

To ensure consistent equal treatment of biomethane with biogas used on site and with other biomass fuels, the currently applicable fossil fuel comparator for electricity generation must be uniformly maintained for all bioenergy carriers.

However, the introduction of a fossil fuel comparator of 94 g CO_2eq/MJ for biomethane for purposes other than transport may, in certain cases, be beneficial for biomethane suppliers—for example, where direct support for biomethane production and injection into the grid is to be granted, or where, within the framework of emissions reporting under the new European fuel emissions trading system (ETS2), a zero-emission factor is to be applied to the quantity of sustainable biomethane placed on the market. The newly introduced 94 gCO_2eq/MJ for biomethane injected into the gas grid is useful for Article 29 sustainability/mitigation demonstrations (for installations above 200 m^3/h biomethane throughput) and for taxonomy-aligned reporting—but it is not an additional end-use comparator and should not be treated as such.

In many cases, the biomethane supplier does not have sufficient knowledge of the intended use of the supplied biomethane or of the end user's plant configuration. Proof of sustainability for biomethane could therefore be provided in these cases using the new fossil fuel comparator in combination with a flat-rate greenhouse gas reduction requirement of e.g. 70 percent (until the end of 2029) and 80 percent (from 2030 onwards).

2.6 Methodology for calculating the accumulation of soil carbon

The implemented methodology for calculating the accumulation of soil carbon (ESCA) resulting from improved agricultural practices calls for reconsideration. In its present form, it imposes disproportionate economic and technical burdens on all participating economic actors, limiting broad and effective engagement.

To address this, we suggest the introduction of an additional calculation pathway that draws on scientifically validated location-specific datasets (e.g. ICCP frameworks). Such an approach would enable a robust and credible assessment of soil carbon accumulation, providing stakeholders with information of sufficient quality to support informed decision making. At the same time, it would help reduce administrative complexity and lower barriers to participation, thereby fostering wider adoption and improving overall system feasibility. In addition, standard values for emission credits from established soil improvement measures are required. For example, for the use of perennial substrates, reduced or zero-tillage, improved crop/rotation, the use of cover crops, including crop residue management, and the use of organic soil improver (e.g. compost, manure fermentation, digestate, biochar, etc.).

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