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Frequently Asked Questions

Regarding Monitoring and Reporting in the EU ETS

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This document is part of a series of documents provided by the Commission services for supporting the implementation of Commission Regulation (EU) No. 601/2012 of 21 June 2012 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council¹.

The guidance represents the views of the Commission services at the time of publication. It is not legally binding.

This document takes into account the discussions within meetings of the informal Technical Working Group on the Monitoring and Reporting Regulation under the WGIII of the Climate Change Committee (CCC), as well as written comments received from stakeholders and experts from Member States.

In general, this document is to be considered specific for operators of stationary installations. However, some questions may also be relevant for aircraft operators. In such cases references to “operators” may also be read as “aircraft operators”, where relevant.

All guidance documents and templates can be downloaded from the Commission’s website at the following address: http://ec.europa.eu/clima/policies/ets/monitoring/documentation_en.htm.

¹ <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:181:0030:0104:EN:PDF>

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1 GENERAL ISSUES

1.1 What type of costs are included in or excluded from the determination of unreasonable costs?

The last sentence of Article 18(1) of the MRR states that “*the competent authority shall consider costs unreasonable where the cost estimation exceeds the benefit.*” Besides the clarification that “*costs shall include an appropriate depreciation period based on the economic lifetime of the equipment*” there is no further definition of what kinds of costs are included or what kinds are excluded. In general, only those costs that are additional to a reference system should be taken into account, i.e. higher costs compared to existing equipment or costs of a more expensive (but more accurate or reliable) equipment less the costs of equipment that would have been purchased, i.e. without monitoring obligations under the EU ETS.

The following type of costs can be considered relevant:

- Investment costs: Those costs shall be based upon an appropriate depreciation period. Where appropriate, a suitable interest rate may be applied
- Operating & Maintenance (O&M) costs: Those costs include costs for any out-sourced calibration or maintenance. It should also include, for the sake of equal treatment, any internal labour costs related to O&M. Only those labour costs shall be taken into account for which the operator can demonstrate to the satisfaction of the competent authority that they can be clearly attributed to the improvement under consideration.
- Costs related to changes in operations: Those costs may occur e.g. if the installation of measurement equipment requires a temporary shutdown of operations. Again, only those costs shall be taken into account for which the operator can demonstrate to the satisfaction of the competent authority that they can be clearly attributed to the installation of the new equipment. If a shutdown was planned anyway it shall not be taken into account.
- Any other costs: Those costs may include, e.g. costs of sampling, costs for additional analyses,...

In some cases some costs, e.g. costs related to maintenance shutdowns or instrument replacements may occur not every year. For such cases those costs should be summed up over the whole depreciation period and divided by the number of years of this depreciation period.

Example:

For assessing whether the acquisition of a measurement instrument incurs unreasonable costs the operator wants to calculate the annual O&M costs. The depreciation period of this investment has been agreed to be 10 years. In the manufacturer’s specification of the instrument it is specified that special maintenance is required every three years. Associated O&M costs are 3,000 € each. What are the annual costs of this special maintenance?

The operator determines the annual costs to be 900 €/year since this special maintenance will be necessary three times over the whole depreciation period resulting in 9,000 €. Dividing by the depreciation period of ten years provides the result. Alternatively, simply dividing those 3,000 € by three may also be an acceptable approach, where considered more appropriate, e.g. if the technical lifetime significantly deviates from the economic lifetime.

To determine whether costs can be considered unreasonable you could consider using the tool for unreasonable costs provided on DG CLIMA’s homepage:

http://ec.europa.eu/clima/policies/ets/monitoring/documentation_en.htm

1.2 Is it possible to apply a mass balance approach to activities, for which the MRR does not explicitly allow a mass balance approach?

No, the MRR does not allow a mass balance approach to be applied except for activities for which it is an explicitly stated option. In particular for combustion activities mass balance is only applicable if:

- The installation is a gas processing terminal (in this case Annex IV, section 1(B) allows use of a mass balance in accordance with Article 25);
- Another Annex I activity of the EU ETS Directive apart from the combustion activity is carried out and Annex IV of the MRR allows or requires the use of a mass balance in accordance with Article 25 for that specific activity; or
- The proposed mass-balance methodology is applied to de-minimis source streams only. In this case the mass balance would qualify as an allowed estimation method.

When the activity does not foresee monitoring using mass balance such an approach can in principle only be applied as a fall-back approach pursuant to Article 22. As a consequence, the operator has to check and report regularly in accordance with Article 69(1) and (3) whether the monitoring method can be improved, e.g. by installing measurement instruments. However, under specific circumstances the MRR also allows for a mass balance approach without explicitly mentioning it as such. Article 27(1), point (b) and Article 27(2), allow determination of activity data based on aggregation of metering of quantities according to the following formula (also see section 6.1.2 of Guidance Document 1):

$$Q = P - E + (S_{begin} - S_{end})$$

Where:

Q Quantity of fuel or material applied in the period

P Purchased quantity

E Exported quantity (e.g. fuel delivered to parts of the installation or other installations which are not included in the EU ETS)

S_{begin} Stock of the material or fuel at the beginning of the year

S_{end} Stock of the material or fuel at the end of the year

The application of this approach is possible if all parameters, i.e. for S_{begin} , S_{end} , P and E are referring to the same source stream.

Example 1:

An installation producing fine organic chemicals is using ethyl acetate as solvent for chemical reactions. Part of this solvent evaporates during the reaction and is combusted in an incinerator connected to the exhaust hood. The rest of the solvent is sold (“exported from the installation”) containing only minor contaminants with negligible impact on changing NCV or EF. In this case the amount of ethyl acetate burned in the incinerator is determined by level readings from the storage tanks, the purchased amounts and the amount sold. Therefore, this monitoring approach is fully in line with the requirements of Article 27(1) point (b).

Example 2:

An installation similar to example 1 is also using other solvents. Now a mixture of these solvents is exported from the installation. Mixing solvents impacts the NCV and EF. Due to this interdependency between the activity data and other calculation factors, the materials entering and leaving the installation cannot be considered *one* source stream. Therefore this fuel / material balance cannot be considered to be covered by Article 27(1) point (b). Hence, a mass balance monitoring approach can only be used here if the installation is approved to apply it as a fall-back monitoring methodology under Article 22 or all the solvents involved fall within the de minimis threshold.

1.3 How to determine unreasonable costs when applying no-tier (fall-back) monitoring approaches for activity data?

General considerations

According to Article 22 of the MRR a no-tier (fall-back) monitoring approach can only be applied if “*applying at least tier 1 under the calculation-based methodology [...] and a measurement-based methodology [...] is technically not feasible or would incur unreasonable costs*”.

Please note that the term “at least tier 1 under the calculation-based methodology” implies that a no-tier approach is already applied for one source stream if not at least tier one is applied for one single parameter, i.e. the activity data or any calculation factor, , except for de-minimis source streams. Therefore, a fall-back methodology should only be applied to the specific part(s) of the calculation or measurement-based methodology that does not meet at least tier 1. E.g. to the extent possible, available default values should be used for calculations and the no-tier approach should be limited to the parameters where no such factors are available.

Example 1:

The amount of CO₂ emitted from a refinery gas source stream cannot be determined by applying tiers due to unreasonable costs. Due to the availability of default values for NCV and EF in Annex VI (compliant with tier 1) the operator should apply a no-tier approach only for activity data. Only where the operator can demonstrate to the satisfaction of the competent authority that the default values are not applicable (e.g. because they apply to another type of refinery gas composition), an estimation methodology for calculating directly the emissions by other means may be developed.

Activity data

For fall-back monitoring approaches for activity data it has to be assessed first if the methodology applied really constitutes a no-tier approach. It can be distinguished between:

- a. Activity data is determined in accordance with Article 27² (i.e. continuous metering or aggregation of metering of quantities) but the uncertainty related to the measurement is higher than the uncertainty allowed under tier 1, OR
- b. Activity data is not determined in accordance with Article 27. Note here that not complying with the requirements in this Article means that you don't comply with any tier. Therefore, any such methodology has to be considered as a fall-back approach and can only be applied if the application of at least tier 1 is not technically feasible or would incur unreasonable costs.

For a) please be aware that an indirect measurement of activity data, e.g. by addition or subtraction of two or more fuel/material flows or batches can also be considered as complying with Article 27. For determination of the applied tier for such cases rules for error propagation must be applied (see Annex III of MRR GD4 on Uncertainty). If the uncertainty achieved complies at least with the relevant tier 1 requirements the determination of activity data is not a fall-back approach.

If assessment shows that the approach is actually a fall-back approach, it has to be demonstrated that applying at least tier 1 of a “conventional” tier approach is technically not feasible or would incur unreasonable costs. For the determination of the incurrance of unreasonable costs when applying at least tier 1 for activity data it has to be assessed whether the costs exceed the benefit. In order to calculate the benefit the difference between the uncertainty currently achieved and the uncertainty

² Article 27(1): “The operator shall determine the activity data of a source stream in one of the following ways:

- (a) based on continual metering at the process which causes the emissions;
- (b) based on aggregation of metering of quantities separately delivered taking into account relevant stock changes.

threshold of the tier must be used as the improvement factor. This approach is relevant regardless whether a) or b) is the reason for deviation because both have a direct impact on the accuracy of activity data. The improvement factor of 1% in Article 18(3) shall not apply here. Therefore, the uncertainty related to the determination of activity data currently achieved has to be assessed in any event and has to be used for calculating the improvement factor.

Note that the higher (the worse) the uncertainty achieved by a fall-back approach the more likely it is that the costs do not exceed the benefit, i.e. the more difficult it will be to demonstrate unreasonable costs. This is the case because the improvement factor feeding into the calculation will be higher. Improving the monitoring methodology of a fall-back approach in terms of reducing its associated uncertainty (e.g. by applying a better estimation method) may lead to a lower (better) uncertainty achieved. As a consequence, costs for meeting at least tier 1 (using measurement equipment to determine the activity data) may more likely be unreasonable after such improvement.

Example 2 (assessing whether the approach proposed is to be considered a fall-back):

A fine organic chemical plant is burning contaminated organic solvents in an incinerator with a heat recovery boiler (see the example in section 1.2). Installing a measurement instrument for the solvent flow (minor source streams) would incur unreasonable costs. The operator proposes calculating the activity data by an energy balance taking into account the measurable heat (i.e. steam) produced and the energy input from natural gas used for auxiliary firing. This approach is clearly not complying with the requirements of Article 27 and should be considered as a fall-back approach. In this case the operator will have to demonstrate pursuant to Article 22 that the application of at least tier 1 is not technically feasible or would incur unreasonable costs.

Note: Pursuant to Article 22(b) the operator has to assess and quantify each year the uncertainties in accordance with the ISO Guide to the Expression of Uncertainty in Measurement (JCGM 100:2008), or another equivalent internationally accepted standard. Furthermore he must demonstrate that the uncertainty for the total emissions of the installation is below 7.5% (the threshold for a category A installation under Article 22(c)). For calculating the uncertainty for the total emissions of the installation please consult “Example 9” of Guidance Document 4 on Uncertainty.

1.4 To what extent are the tier requirements for minor source streams different to those for major source streams?

In accordance with Article 26(1) the required tiers are:

- at least the tiers listed in Annex V for category A installations, or where a calculation factor of commercial standard fuels,
- the highest tier as defined in Annex II for all other cases.

Operators may deviate from applying those tiers where they are technically not feasible or would incur unreasonable costs (a tier one level lower than required for category C installations and up to two levels lower for category A and B installations, with a minimum of tier 1). Under certain conditions even lower tiers, with a minimum of tier 1, may be allowed by the Competent Authority.

Paragraph 2 of Article 26 specifies for minor source streams that the highest tier which is technically feasible and does not incur unreasonable costs, with a minimum of tier 1, shall be applied. Therefore, also for minor source streams the use of a tier lower than the required tier is allowed only if the operator demonstrates to the satisfaction of the competent authority that the required tiers are technically not feasible or would incur in unreasonable cost. Please note that no reference is made here that there are any further derogations from paragraph 1. Therefore, for category A installations and com-

mercial standard fuels tiers in Annex V are also to be considered as the required tiers for minor source streams.

As a consequence, the main difference between the tier requirements for major and for minor source streams is that there is no threshold or time limit when deviating from the tier requirement. In any event this is true if at least tier 1 is applied and applying the required tiers is technically not feasible or would incur unreasonable costs (see examples below).

Example 1: Category B or C installation, liquid fuel

| | Tier required (highest tier in Annex II) | Minimum tier (technically not feasible or unreasonable costs) | Absolute minimum tier (transitional period of up to three years) |
|-------|--|---|--|
| Major | 4 | 3 (for Cat. C) 2 (for Cat. B) | 1 |
| Minor | 4 | 1 | n.a. |

Example 2: Category A installation, liquid fuel

| | Tier required (Annex V) | Minimum tier (technically not feasible or unreasonable costs) | Absolute minimum tier (transitional period of up to three years) |
|-------|-------------------------|---|--|
| Major | 2 | 1 | n.a. |
| Minor | 2 | 1 | n.a. |

1.5 Is it possible to apply tier 2a for net calorific value (NCV) and tier 2b for emission factor (EF) or vice versa for the same fuel?

No, unless the EF is consistent with the use of NCV and the corresponding oxidation factor

Tier 2a and 2b are considered to be on the same accuracy level in the MRR, hence there is no preference to choose one or the other. Furthermore, there is no provision that the same tier, i.e. tier 2a or 2b or another tier, has to be applied for NCV and EF for the same fuel.

However, Article 24(1) states: “Under the standard methodology, the operator shall calculate combustion emissions per source stream by multiplying the activity data related to the amount of fuel combusted, expressed as terajoules based on net calorific value (NCV), with the corresponding emission factor, expressed as tonnes CO₂ per terajoule (t CO₂/TJ) consistent with the use of NCV, and with the corresponding oxidation factor.”

If the NCV or EF contradict this principle, this approach is not allowed. To avoid such inconsistency please contact your competent authority regarding background information on certain default values (e.g. values from the National Inventory used for tier 2a) or the IPCC Guidelines (tier 1).

1.6 What does “additional effort” mean in case of de-minimis source streams or for installations with low emissions?

When reading the MRR the term „additional effort“ is encountered twice:

- Article 26(3): *For activity data and each calculation factor for de-minimis source streams, the operator may determine activity data and each calculation factor by using conservative estimations instead of using tiers, unless a defined tier is achievable without additional effort.*
- Article 47(6): *By way of derogation from Article 26(1) the operator of an installation with low emissions may apply as a minimum tier 1 for the purposes of determining activity data and calculation factors for all source streams, unless higher accuracy is achievable without additional effort for the operator, without providing evidence that applying higher tiers is technically not feasible or would incur unreasonable costs.*

In both cases “additional effort” means effort in addition to monitoring systems or monitoring methodologies already in place. This usually refers to systems or methodologies already in place before considering improvements, or, where appropriate, if there were no ETS monitoring obligations. Therefore, it should not be considered to incur an additional effort to use available data for a second purpose (i.e. GHG emissions monitoring), including any associated administrative or bureaucratic effort (e.g. writing procedures or providing evidence).

Example 1:

An installation with low emissions is covered by the EU ETS from 2013 onwards because of its production of bulk organic chemicals. For quality assurance and for commercial purposes the installation is analysing (indirectly) the carbon content³ of each source stream involved in the reaction in accordance with Articles 32 to 35, i.e. compliant with tier 3 for the determination of the carbon content. Although eligible to apply tier 1 under Article 47(6), compliance with tier 3 in effect requires no additional effort because it is already being met. The requirement to provide a sampling plan to the Competent Authority may be caused only by the EU ETS monitoring obligations, but it should not be considered to cause additional effort because it requires only to lay down in writing what is already done.

Example 2:

The customers of this same installation are now only requiring that the main compound of the product exhibits a purity of > 95 %. Due to the fluctuation of the production process, the impurities are not constant and not identified for quality assurance. In this case, the analytical results can not be considered to comply with the requirements of Articles 32 to 35. Full compliance would require a more demanding analytical method and should therefore be considered as requiring additional effort. As a consequence, the operator will not be required to apply tier 3 but to use available default values instead. However, note that the lower the purity the less appropriate it will be to assign this product to a certain material for which default values are available. If default values are not available the operator will have to propose a fall-back approach demonstrating that improving his analytical method would otherwise incur unreasonable costs.

³ *Explanation of the term “indirect analyses”:* It is frequently found that the purity of substances must be regularly analysed before the input materials can be used for the process, or before the products can be sold. These are analyses which are done already without an ETS obligation. For this example we assume that the purity of the substances are analysed by a suitable method, e.g. HPLC. Furthermore also the nature of the main impurities are known. In many cases the impurities are predominantly water or other solvents. Thus, as soon as the purity and the type of substances are known, the carbon content can be determined by stoichiometry. This is what we refer to as “indirect analysis” in the example. A “direct” analysis would be an elementary analysis for determining the (total) carbon content. The “additional effort” here is the mere application of one additional stoichiometric calculation, which can be easily assumed negligible effort.

1.7 How to determine the oxidation factor by taking into account the carbon content of ashes?

The annual emissions are calculated by:

$$Emissions = FQ \cdot NCV \cdot EF \cdot OF$$

where:

FQ..... Quantity of fuel [t]

NCV.... Net calorific value [TJ/t]

EF..... Emission factor [t CO₂/TJ]

OF..... Oxidation factor

There are two possible approaches to calculate those annual emissions:

- Emissions are calculated for each batch or delivery period the analytical value is representing. The total emissions are obtained by adding up all emissions calculated.
- Determine annual weighted averages for each calculation factor and calculate the annual emissions according to the formula above.

Where not all calculation factors represent the same batch or delivery period, method a) will not be applicable. For this case the following example gives guidance on the calculation route b).

Example:

An operator is burning lignite. Each analytical value for NCV and EF determined in accordance with Articles 32 to 35 is representative for each batch of lignite. Note that the EF will be calculated from the carbon content (CC) and the NCV ($f=3.664^4$) according to:

$$EF = CC \cdot f / NCV$$

The OF is determined by analysis of the carbon content of the ash and by the amount of ash obtained upon combustion in accordance with Articles 32 to 35 as well. The oxidation factor will be obtained by:

$$OF = 1 - \frac{CC_{ash} \cdot Quantity_{ash}}{CC_{fuel} \cdot Quantity_{fuel}}$$

The batches of ash used for analysing their carbon content do not correspond necessarily with the fuel batches. Still, Annex VII requires to also analyse the OF at least six times per year. Therefore, the OF can be calculated as follows.

⁴ Article 36(3): "For the conversion of the carbon content into the respective value of a CO₂ related emission factor or vice versa, the operator shall use the factor 3.664 t CO₂/t C."

| Batch | FQ [t] | NCV [GJ/t] | EF [t CO ₂ /TJ] | CC [t C/t] | FQ x CC [t C] |
|---|-----------|------------|----------------------------|------------|---------------|
| 1 | 20,000.00 | 11.9 | 101.6 | 0.3300 | 6,600 |
| 2 | 22,000.00 | 12.1 | 101 | 0.3335 | 7,338 |
| 3 | 25,000.00 | 11.95 | 101.3 | 0.3304 | 8,260 |
| 4 | 21,000.00 | 12.06 | 101.8 | 0.3351 | 7,037 |
| 5 | 23,000.00 | 11.85 | 102.3 | 0.3309 | 7,610 |
| 6 | 24,000.00 | 11.9 | 101.5 | 0.3297 | 7,912 |
| 7 | 23,000.00 | 11.93 | 102.2 | 0.3328 | 7,654 |
| 8 | 24,000.00 | 11.91 | 101.6 | 0.3303 | 7,926 |
| Sum (=total amount of carbon in lignite) | | | | | 60,335 |

| Batch | Q _{ash} [t] | CC _{ash} [t C/t] | Q _{ash} x CC _{ash} [t C] |
|---|----------------------|---------------------------|--|
| 1 | 1,589 | 0.0207 | 32.9 |
| 2 | 1,900 | 0.0180 | 34.3 |
| 3 | 2,108 | 0.0193 | 40.7 |
| 4 | 1,573 | 0.0243 | 38.3 |
| 5 | 1,764 | 0.0203 | 35.8 |
| 6 | 2,073 | 0.0229 | 47.4 |
| Sum (=total amount of carbon in ash) | | | 229.4 |

The weighted average annual NCV is calculated by:

$$NCV = \frac{\sum_i NCV_i \cdot FQ_i}{\sum FQ} = 11.95 \frac{GJ}{t}$$

The weighted average annual EF is calculated by:

$$EF = \frac{\sum_i EF_i \cdot NCV_i \cdot FQ_i}{\sum_i NCV_i \cdot FQ_i} = 101.66 \frac{tCO_2}{TJ}$$

The weighted average annual OF is calculated by:

$$OF = 1 - \frac{CC_{ash} \cdot Quantity_{ash}}{CC_{fuel} \cdot Quantity_{fuel}} = 1 - \frac{229.4}{60,335} = 99.62 \%$$

The annual emissions are calculated by:

$$Emissions = 182,000 \cdot 11.95 / 1,000 \cdot 101.66 \cdot 99.62\% = 220,260 tCO_2$$

In principle, this approach for determining OF is based on a mass balance, but not based on Article 25 of the MRR. Therefore, the quantity of ash is not considered a separate source stream and no dedi-

cated uncertainty thresholds apply. However, as a result of analogy, operators should strive to apply an uncertainty level similar to the tier level which would be required, if the ash were a source stream of its own. It must be noted that in most cases such “ash source stream” would be a de-minimis source stream. The appropriate method for determining the ash amount, and therefore the associated uncertainty, will be taken from suitable standards. For sampling and analysing Articles 32 to 35 (requirements for analyses) apply.

Note that alternatively the oxidation factor can be determined using the carbon content of the ash and ash content of the fuel (AC_{fuel} , %) instead of determining the amount of ash. This alternative does not require the ash quantity to be measured, only the percentage ash content of the fuel and carbon content of the resultant ash.

$$OF = 1 - \frac{CC_{ash} \cdot AC_{fuel}}{CC_{fuel}}$$

The ash content of a fuel is commonly obtained by a loss on ignition method where the fuel is burned until no more mass loss is observed. However, for this method burning of the fuel is done under laboratory conditions which may lead to different results than the fuel combustion in the boiler (e.g. due to different particle sizes and morphology as well as different retention times). On the other hand, accurate measurement of ash quantity can be problematic if water is used to convey (and cool) the ash. Therefore, preference should be given to the method giving higher accuracy and the operator has to ensure that emissions are not underestimated.

1.8 Application of Article 31(4); clarification on how to apply the 1% rule

Article 31(4) states that *“upon application by the operator, the competent authority may allow that the net calorific value and emission factors of fuels are determined using the same tiers as required for commercial standard fuels provided that the operator submits, at least every three years, evidence that the 1 % interval for the specified calorific value has been met during the last three years.”*

An operator may now demonstrate to the competent authority that based on analyses in the past the NCV or EF of a specific fuel was determined to be within this 1% interval. This may be done by calculating twice the standard deviation (a 95% confidence interval) of those historic values and check whether it is lower than 1%. However, as Article 31(4) requires provision of evidence at least every three years an operator will have to start sampling and analysing again for the following three years to demonstrate that the 1% interval is not exceeded. Note that such homogeneous fuels may only require lower frequencies of analyses than listed in Annex VII due to application of the 1/3-rule or the in-currence of unreasonable costs.

The most common cases for application of this Article will be fuels or materials used by many operators, exhibiting such constant values for NCV or EF within one Member State or region. In some countries natural gas will meet such requirements and reliable historic analytical values will be available from e.g. network distribution owner data on a Member State or regional level. **Operators of category B and C installations will then be allowed as well to apply e.g. tier 2a by using values from the National Inventory instead of analysing themselves.**

It can be considered good practice by CAs to publish the relevant findings on the 1% interval and respective default values for common fuels or materials, such that all operators concerned can make use of Article 31(4) without making all their own investigation. In particular for default values determined for their use in the National Inventory CAs may have a better knowledge about any regional deviations than a single operator.

1.9 Article 26(3): What does a conservative estimate mean in practice, what does it look like? Are there any generic figures that could be used, for example emissions from a typical diesel back-up generator?

Please see “Exemplar for Uncertainty Assessments (installation with low emissions, Diesel)”

1.10 Does an operator of an installation with low emissions have to submit improvement reports?

Yes, but only under certain circumstances. Operators of installations with low emissions must submit an improvement report in accordance with Article 69(1) and in response to a verifier’s report noting non-conformities. They also have to take into consideration the verifier’s recommendations in their monitoring, but are exempted from having to provide a corresponding improvement report to the competent authority in this particular respect (Article 47(3)).

Articles 69(1) and (2) require all operators to submit an improvement report if the tiers required by Article 26(1) are not met. The MRR does not differentiate between low emitters and other categories with regard to use of highest tiers. However Article 47(6)⁵ exempts installations with low emissions from the requirements in Article 26(1) and allows application of tier 1 as a minimum.

Therefore, operators of installations with low emissions must submit an improvement report:

- in response to verifier’s findings of non-conformities (Article 69(4)), AND
- every four years (category A installation) if they are applying fall-back approaches (Article 69(3)).

1.11 Does the determination of unreasonable costs require the use of a depreciation period? How is it determined and how should evidence be provided?

For the determination of unreasonable costs the second paragraph of Article 18(1) requires that the operator “[...] shall include an appropriate depreciation period based on the economic lifetime of the equipment.”

The economic lifetime is a term that is not defined in the MRR but refers to its meaning used in taxation laws. For a lot of assets (e.g. measuring instruments) national taxation laws or supplementing guidance (e.g. published by the respective Ministry of Finance) provide asset-specific depreciation periods for several economic sectors.

Nevertheless, those values are not legally binding for the EU ETS but may be considered as reference values. The operator’s justification for proposing a different depreciation period may be taken into account, e.g. where a measuring instrument is used in a corrosive environment.

⁵ Article 47(6): “By way of derogation from Article 26(1) the operator of an installation with low emissions may apply as a minimum tier 1 for the purposes of determining activity data and calculation factors for all source streams, unless higher accuracy is achievable without additional effort for the operator, without providing evidence that applying higher tiers is technically not feasible or would incur unreasonable costs.”

1.12 Do CO₂ emissions stemming from the purification of natural gas have to be monitored and reported?

They have to be monitored and reported only if the CO₂ is released in a combustion process by using either a standard combustion methodology or a mass balance methodology, where a calculation based monitoring approach is applied or by using CEMS. This means that there is no monitoring and reporting requirement for CO₂ that is part of the imported raw natural gas but is at no point in the process fed into a combustion process. In the simplest case, CO₂ contained in any natural gas will be reported by including this CO₂ when determining the emission factor for applying it in a standard calculation method.

In upstream industries, the situation is slightly more complex: Natural gas usually requires several purification steps after extraction to meet the specifications of the gas network operator. Those purification steps are normally done in a gas processing terminal and involve e.g. gas separation from liquid organic compounds and water. If the CO₂ or H₂S (hydrogen sulphide) concentration (acid gas) exceeds the thresholds of the gas network operator's specification, a removal of those impurities is also required. This is most commonly achieved by separating those acidic gases from the main organic components in the natural gas by an amine treatment system. In subsequent steps the CO₂ and H₂S are separated from each other as well. H₂S will generally be converted into saleable products (e.g. to sulphur in a CLAUS unit)⁶ and the gas flow containing very high CO₂ concentrations will be released to the air.

This gas flow containing CO₂ in high concentrations often also contains some VOC impurities and therefore can not be released directly to the atmosphere without a thermal conversion of those VOCs. Because this conversion is an oxidation of fuels this conversion qualifies as combustion within the meaning of Article 3(t) of the EU ETS Directive⁷, and the off-gas is regarded a fuel. As a consequence, the CO₂ contained in this fuel is inherent CO₂ according to Article 48⁸ and needs to be monitored and taken into account for the emission factor of this fuel.

It has to be noted that gas processing terminals are normally covered by the EU ETS due to their combustion activities > 20 MW (e.g. steam production for the purification process) and there is no special activity unlike for liquid fuel refineries. However, section 1 of Annex IV also provides the opportunity for combustion processes taking place in gas processing terminals to be monitored by a mass balance methodology in accordance with Article 25. In this case, the CO₂ emissions may simply be calculated as the difference between the amount of natural gas imported by the installation multiplied by the corresponding carbon content and amount of natural gas exported from the installation multiplied by the corresponding carbon content.

⁶ Note: the H₂S enriched gas flow may still contain a significant concentration of CO₂. If this gas flow is also fed into a combustion unit (e.g. CLAUS unit), this CO₂ needs to be monitored and reported as well.

⁷ Article 3(t) of the EU ETS Directive: "combustion means any oxidation of fuels, regardless of the way in which the heat, electrical or mechanical energy produced by this process is used, and any other directly associated activities, including waste gas scrubbing"

⁸ Article 48: "Inherent CO₂ which is transferred into an installation, including that contained in natural gas or a waste gas including blast furnace gas or coke oven gas, shall be included in the emission factor for that fuel."

1.13 Do fuels stored in pressurised gas-bottles (e.g. propane, acetylene,..) and used for certain process steps within the installation have to be monitored and reported?

In principle, yes they have to be monitored regardless of whether the fuel is stored in tanks, in pressurised gas-bottles or is directly imported from an external fuel network (e.g. natural gas). It is only relevant in which technical unit those fuels are used and whether those units have a technical connection with the activities carried out on that site⁹. If those units are stationary and have a technical connection with the activities carried out (e.g. laboratory units), this unit has to be included in the greenhouse gas permit. Hence all fuels combusted in that unit must be listed as source streams in the monitoring plan.

1.14 Do non-significant source streams (e.g. with single digit annual emissions) and mobile sources need to be covered by the Monitoring Plan?

Yes, all source streams need to be covered by the permit and the monitoring plan. There is no threshold laid down in the MRR with respect to the annual emissions stemming from each source stream.

In contrast to that, mobile sources are in general excluded. In section 2.3.1 of the “Guidance on Interpretation of Annex I of the EU ETS Directive (excl. aviation activities)”¹⁰ it is clarified that “Excluded from the EU ETS is “true” mobile machinery (trucks, forklifts, bulldozers...), i.e. machinery which has the purpose of being mobile at the moment of performing its tasks.” For instance, mobile flares have to be monitored and reported because it is not their purpose being mobile at the moment of performing its tasks. For further explanation please consult the abovementioned Annex I guidance.

For emissions from non-significant sources related to stationary units it may not be necessary to report emissions from individual emission sources, where these can be grouped into combined source streams (i.e. by fuel type).

Example 1: Natural gas is supplied to site via a main site gas meter; the gas is consumed by a number of emission sources including boilers, canteen equipment and laboratory units. In this case the emission sources can be grouped into one source stream and fuel consumption determined via the single gas meter.

Example 2: A number of emergency generators are fuelled by gas oil; the generators may only be used for very small periods and so annual emissions are low. Gas oil for the generators is taken from a storage tank which is used to supply fuel to a number of other emission sources at the installation. Fuel consumption for reporting purposes can therefore be based on deliveries and/or stock tank measurements for this source stream.

In the case of small emission sources which cannot be grouped as they use unique fuel streams then the monitoring approach should be appropriate to the scale of emissions. It is likely that very small sources will fall into the de-minimis category and therefore under the Monitoring and Reporting Regulation a no tier approach may be applied using a conservative estimation method.

⁹ Article 3(e) of the EU ETS Directive: “installation means a stationary technical unit where one or more activities listed in Annex I are carried out and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution”

¹⁰ http://ec.europa.eu/clima/policies/ets/docs/guidance_interpretation_en.pdf

Example 3: Small heating units supplied from propane cylinders; this is the only use of propane at the installation and represents a de-minimis source stream. Emissions are determined using a conservative estimation method based on the number of cylinders purchased each year.'

1.15 What is the difference between flares and post-combustion units?

Identifying relevant units correctly impacts the effort which is necessary to comply with the monitoring requirements in the MRR. Fuels combusted in post-combustion units, also often named incinerators, need to be monitored like all other fuels in combustion units whereas for flares less stringent requirements apply. Nevertheless, there is no clear legal definition of flares and post-combustion units, neither in the EU ETS Directive nor in the MRR.

However, the definition of safety flaring in Article 3(p) of the Benchmarking Decision (278/2011/EU) can be used as a suitable starting point for this distinction. In this Article safety flaring is defined as *“the combustion of pilot fuels and highly fluctuating amounts of process or residual gases in a unit open to atmospheric disturbances which is explicitly required for safety reasons by relevant permits for the installation”*.

In other words, flaring can be considered as safety flaring if all three following conditions are met:

1. The flaring is required for safety reasons (in particular if required by a relevant permit), AND
2. The combustion takes place in a unit open to atmospheric disturbances (the combustion in other units is not covered), AND
3. The amounts and/or composition of process or residual gases are highly fluctuating.

This definition implies that the predictability of the combustion activity is a relevant parameter for the distinction. Flaring is often encountered for processes in which combustible gas flows are transported under high pressure through ducts for chemical reaction (e.g. production of polyethylene from pressurized ethylene gas) or purification (e.g. refineries).

However, the MRR does not distinguish between flaring and safety flaring. For flaring other than safety flaring often the criterion of high fluctuations is not met. Therefore, criteria 1 and 3 above can only serve as indicators but the focus of the assessment should be on criterion 2.

For further reading, please consult Guidance Document 8 accompanying the benchmarking rules. This document can be downloaded from the following website:

http://ec.europa.eu/clima/policies/ets/cap/allocation/documentation_en.htm

All other post-combustion processes not meeting the above-mentioned specifications can be considered as post-combustion units, in particular combustions not taking place in a unit open to atmospheric disturbances¹¹. Post-combustion is often encountered in processes where the combustible gas is transported using a carrier gas (e.g. solvents for the production of fine organic chemicals, solvents in painting resins,..) in combustion units which are not open to atmospheric disturbances. Note that units equipped with a heat recovery steam generator are indicating that this unit is not open to atmospheric disturbances and are therefore to be considered as post-combustion units.

¹¹ Note that this also includes "shrouded flares", i.e. flares where combustion is "open to atmospheric disturbances" but a shroud is provided to hide the flame.

2 BIOMASS ISSUES

2.1 What is the “preliminary” emission factor and how is it determined?

Article 3(35) of the MRR defines: ‘preliminary emission factor’ means the assumed total emission factor of a mixed fuel or material based on the total carbon content composed of biomass fraction and fossil fraction before multiplying it with the fossil fraction to result in the emission factor.

This means that the “preliminary” emission factor is the emission factor, expressed as t CO₂ / TJ or t CO₂ / t, which takes into account the total CO₂ released by the combustion of the fuel or conversion of the material, regardless of whether the CO₂ is stemming from fossil or biomass carbon. Where the (preliminary) emission factor is determined by analyses in accordance with Articles 32 to 35 (tier 3) this emission factor is determined the same way as for purely fossil fuels or materials. Where default values are used for the determination of the preliminary emission factor, relevant sources are *inter alia* Annex VI (tier 1), section 7.2.1 of Guidance Document 3 or other values used in the IPCC Guidelines or in the National Inventory (tier 2a).

Example:

An installation is burning wood-based panels waste. The carbon content of the waste wood panels is analysed: Carbon Content (CC) = 0.5 t C/t waste. 95% of the carbon contained in this source stream is stemming from biomass (the fossil carbon is contained in the resins used for gluing the wood fibres). The net calorific value (NCV) is determined to be 15 GJ/t waste.

To determine the preliminary emission factor (EF_{pre}) expressed as t CO₂/TJ, the following equation is used (see section 6.3.1 of Guidance Document 1):

$$EF_{pre} = CC_{total} \cdot f / NCV$$

With factor f being 3.664 t CO₂/t C the preliminary emission factor is 122 t CO₂/TJ. The preliminary emission factor (EF_{pre}) corresponds to the total CO₂ emitted from this source stream regardless whether it is stemming from fossil or biomass sources.

The ETS reportable emissions are calculated by (for detailed description see section 4.3.1 of Guidance Document 1):

$$Em = FQ \cdot NCV \cdot EF_{pre} \cdot (1 - BF) \cdot OF$$

The fact that 95% of this CO₂ is stemming from biomass is taken into account by the term “1 minus biomass fraction” (1-BF). The biomass fraction is defined as the ratio of carbon stemming from biomass to the total carbon content of a fuel or material. Hence, this is also the ratio of CO₂ emitted stemming from biomass to the total CO₂ emitted.

Note that in the case of biofuels and bioliquids sustainability criteria apply (see GD 3). If those criteria are not satisfied, the biomass fraction shall be assumed to be zero, i.e. all carbon is treated as fossil. The preliminary emission factor is equal to the final emission factor in those cases.

2.2 What happened to the MRG concept of “pure biomass”? How should small fossil impurities of otherwise “pure” biomass source streams be monitored?

The MRG 2007 used the term “pure biomass” for source streams containing at least 97% biomass. This was based on the assumption that traded chemicals use a similar term (“purum”) for purity levels where the concentration of the main constituent is usually well below 100% (and also below the content in higher trade qualities such as “purissimum” or “p.a.”). However, the term “pure biomass” sometimes led to confusion. It was sometimes misunderstood such as if the remaining fossil quantity were not required to be reported.

For better clarity the M&R Regulation does not use the term “pure biomass” any more, but still retains the corresponding simplified approaches for biomass sources streams with fossil impurities below 3% (Article 38(4)). Furthermore it is better clarified that for the fossil fraction of such source streams also relatively little monitoring effort is required, because the very low fossil fraction leads to treating it as a de-minimis source stream in most cases. This means that the fossil fraction can be estimated, but conservatively.

2.3 Biomass fraction for waste tyres

Tyres are composed in principle of:

1. Steel carcasses,
2. Textiles (often viscose filament fibres, i.e. biomass),
3. Natural latex,
4. Synthetic latex,
5. Carbon black,
6. Other filler materials (often inorganic).

Only point 3 and (part of) point 2 qualify as biomass. However, composition of tyres varies widely across manufacturers and tyre type (car, truck, tractor). Manufacturers are keeping composition data strictly confidential, and analyses are very demanding due to the virtual impossibility of representative sampling.

Thus, it is advisable to develop default values at the national level, or even EU level, if sufficient data can be collected from Member States. Typical values informally reported are in the range of

- Carbon content = [60...75]%
- NCV = [25...35] GJ/t
- Preliminary emission factor = [80...90] t CO₂/TJ
- Biomass fraction = [20...30]%

[Note: More data is required for substantiating any proposal for default values or at least for narrowing the intervals]

In the absence of more reliable data, the most conservative values have to be used, i.e. high preliminary EF and low biomass fraction, unless evidence for more representative values can be provided by

the operator. As mentioned in question 1.5, Article 24(1) requires the corresponding NCV to be consistent with this EF.¹²

2.4 What are suitable estimation methods to determine the biomass fraction?

According to Article 39 an estimation method may be proposed to the competent authority for approval, if:

- Analysing the biomass fraction by using appropriate standards¹³ is technically not feasible or would incur unreasonable costs, provided that tier 2 for the biomass fraction is required for the specific source stream by the MRR, and
- There are neither suitable default values for emission factor and biomass fraction for mixed fuels and materials nor estimation methods published by the Commission.

Allowed estimation methods must be based on scientifically proven methods. Therefore, a literature research should be carried out giving preference to methods at least partly referring to EN, ISO or national standards as well as to peer-reviewed publications.

A peer-reviewed paper providing a suitable estimation method for determining the biomass fraction has been published for waste-to-energy processes^{14,15}. This method is based on a mass balance (distinguishing between biogenic, fossil, inert fractions and moisture content), including an ash and carbon balance and an energy balance. Furthermore, the O₂ consumption as well as the difference between O₂ consumption and CO₂ emission is relevant. Where different fossil sources are used determining the correct difference between O₂ consumption and CO₂ emission needs to be adjusted by the correct stoichiometric relations, since this method focuses on wastes and assumes that polyethylene is the main fossil source. The advantage of the described method is that it is based on parameters which need monitoring for process control reasons anyway, even if the installation is not covered by the EU ETS.

For fuels or materials originating from a production process with defined and traceable input streams, e.g. waste wood panels or biodiesel, Article 39(2) allows the operator to base such estimation on a mass balance of fossil and biomass carbon entering and leaving the process^{16,17,18}.

Please note that the abovementioned estimation method is different from the “energy balance method” which Article 38(4) allows for estimating emissions for mixed fuels or materials with a biomass content equal to or higher than 97 %. Article 3(38) defines the “*energy balance method means a method to estimate the amount of energy used as fuel in a boiler, calculated as sum of utilisable heat and all relevant losses of energy by radiation, transmission and via the flue gas.*” This method in principle is

¹² Please note that Annex VI(1) is providing a default value for the preliminary emission factor of waste tyres (85.0 t CO₂/TJ). This means that if an operator wants to use this EF he has to provide evidence that the proposed default value for the NCV for waste tyres is consistent with this EF.

¹³ The MRR does not mention specific standards. Appropriate standards may be EN 15440, ASTM D-6866-12, ISO/DIS 13833, ..

¹⁴ [Fellner J, Cencic O, Rechberger H.](#) “A new method to determine the ratio of electricity production from fossil and biogenic sources in waste-to-Energy plants.” *Environ Sci Technol.* 2007; 41(7); p. 2579-2586.

¹⁵ [Obermoser M, Fellner J, Rechberger H.](#) “Determination of reliable CO₂ emission factors for waste-to-energy plants.” *Waste Manag Res.* 2009; 27(9); p. 907-913.

¹⁶ <https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-template-methodology-measuring-fossil-derived-contamination-within-waste-wood>

¹⁷ <https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-fuel-measurement-and-sampling-guidance-may-2013>

¹⁸ <https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-biodiesel-and-fossil-derived-bioliquids-guidance-may-2013>

based on a complete energy balance of a boiler allowing emissions to be related directly to individual input materials. A suitable basis for such an approach is EN 12952-15 “Water-tube boilers and auxiliary installations – Part 15: Acceptance tests.” This standard describes principles for calculating the boiler efficiency as well as formulae for calculating relevant flue gas parameters. This “energy balance method” gives the mass and heat flow of the fuel consumed as the result, allowing the determination of emissions from analysis of the fuel. It is only suitable for estimating emissions for mixed fuels or materials with a biomass content equal to or higher than 97 %. It is not applicable for mixed fuels with a lower biomass content than 97 % or for determination of the biomass fraction of such a fuel.

3 UNCERTAINTY ASSESSMENT

3.1 How does the quality assurance of measurement instruments in accordance with Articles 58(3), point (a) and Article 59 relate to the uncertainty assessment?

Every operator, regardless of the installation’s size or routes taken for determining the uncertainty of activity data, is required to comply with the requirements of Article 58(3)(a) and Article 59.

Article 58(3)(a) requires the putting in place of a written procedure for the quality assurance of the measurement equipment. Article 59 further specifies which measures for such quality assurance have to be performed in order use measuring instruments providing accurate and reliable results. Note that in the case of instruments under national legal metrological the requirements of Article 59 are often met sufficiently without great effort e.g. the check against traceable international standards is achieved by the official calibration.

Article 59 allows for deviation where components of the measuring systems cannot be calibrated. In such a case alternative control activities have to be proposed. As a consequence, the uncertainty assessment cannot be simplified by Routes CO/CT-1 or CO-2a/2b described in Guidance Document 4 but specific uncertainty assessment (Route CO/CT-3) has to be carried out. The obligation to carry out a specific uncertainty assessment does not necessarily mean that this assessment has to be completely started from new (also see section 3.1.1.6 of Guidance Document 4). In these cases uncertainties gathered from the simplifications, Routes CO/CT-1 or CO-2a/2b, might be starting points for further calculations, e.g. via error propagation.

For further reading also see the “Exemplar Uncertainty Assessment”.

3.2 Supplier data: What if the supplier does not provide sufficient information for demonstrating compliance with the required tiers?

Activity data

A measurement system outside the operator’s own control may only be used – pursuant to Article 29(1) – if it “*allows the operator to comply with at least as high a tier, gives more reliable results and is less prone to control risks, the operator shall determine the activity data from measurement systems outside its own control.*” These conditions can be considered to be met if evidence thereof can be provided, e.g. uncertainties from the official calibration protocol. If such evidence cannot be obtained from the trading partner the following steps may be taken:

1. Can evidence be provided that the uncertainty in a reasonable worst case scenario is still better than using the operator's own meters and is at least meeting tier 1? Such evidence may be obtained by demonstrating that e.g. this measuring instrument is subject to national legal metrological control and even the least stringent requirements allow the meeting of a certain tier (also see background information in section 2.2. of the "Exemplar Uncertainty Assessment").
2. If yes, then the tier met in the worst case should be used for further assessments.
 - a. If the tier met in the worst case is meeting at least the required tier then no further evidence is needed.
 - b. If the tier met in the worst case is lower than the required tier, the operator will have to demonstrate that using his own meters to meet the required tiers would incur unreasonable costs or is not technically feasible.
3. If no, then the operator is not meeting at least tier 1 and is in fact applying a fall-back approach. Again, the operator has to demonstrate in this case that using his own meters to meet the required tiers would incur unreasonable costs or is not technically feasible.

Further information can be found in section 3.1.2 of Guidance Document 4 on Uncertainty.

Calculation factors

In some cases operators may want to use calculation factors, e.g. NCV, EF, carbon content,..., provided by the supplier of a fuel or material. Sampling and analysis is carried out by the supplier. However, in such a case it is still the operator's responsibility to demonstrate compliance with the requirements of Articles 32 to 35. This may be achieved by obtaining information and evidence surrounding the sampling plan applied by the third party and evidence that representative samples have been analysed by an accredited laboratory using appropriate standards. If the laboratory is not accredited to EN ISO/IEC 17025 evidence for meeting equivalent requirements has to be provided. If an operator wants to use supplier data for calculation factors the following steps may be taken:

1. Can evidence be provided that an appropriate sampling plan is in place and that analyses are carried out by an accredited laboratory or by a laboratory meeting the equivalent requirements?
2. If yes, then the operator shall be deemed to meet tier 3 for all relevant calculation factors for which this evidence has been provided.
3. If no, then the analytical values obtained from the supplier cannot be considered to meet tier 3. The operator then can either choose:
 - a. To analyse himself in accordance with Articles 32 to 35, OR
 - b. To use available default values. If the tier required for this source stream is lower than tier 3, e.g. in case of a category A installation, then those default values should be used without any further action. If the MRR requires application of tier 3 for the source stream, default values may only be used if the operator can demonstrate that analysing himself would incur unreasonable costs or is technically not feasible.

Please note that before taking into account any justification for not meeting tier 3 in general it has to be assessed whether applying tier 3 but with a lower frequency of analysis (Article 35 and Annex VII) might avoid the incurrence of unreasonable costs.

Where suitable default values are not available and the operator is not able to meet at least tier 1, suggesting that a fall-back approach is required, the operator again has to demonstrate that using his own meters (in accordance with the required tiers) would incur unreasonable costs or not be technically feasible.

Operators are also required to manage their use of supplier data under their written procedure required for control out-sourced processes under Article 58(3)(f) according to the specific requirements of Article 64.

Further information can be found in Guidance Document 5 on Sampling & Analysis.

3.3 Data from more than one supplier: Does the MP have to be changed every time the supplier changes? How to provide proof for achieving the required uncertainty?

Article 14 and 15 lay down circumstances under which an operator shall modify the monitoring plan (MP) and seek approval by the Competent Authority (CA). In general, changes without an impact on the monitoring methodology or impact on the accuracy or reliability of data relevant for reporting should not lead to a modification of the monitoring plan. As a consequence, the most appropriate way to address such changes without significant impact on the MP is by establishing suitable procedures also with respect to the requirements for control of outsourced activities in accordance with Articles 58(3)(f) and 64.

Summaries of those procedures must be described in the MP with such level of detail that the CA can understand the content of the procedure, and can reasonably assume that a full documentation of the procedure is maintained and implemented by the operator. This gives the operator the flexibility to make amendments to the procedure whenever needed, without requiring update of the monitoring plan, as long as the procedure's content stays within the limitations of its description laid down in the monitoring plan (see section 5.4 of Guidance Document 1 for further information about procedures).

Example:

Heavy fuel oil is delivered on trucks owned by different suppliers. The volume flow meters used for determining the purchased amounts are all installed on the trucks, hence outside the operator's own control. A procedure will be established for keeping track of the all measuring instruments involved for determining the activity data of this source stream. A summary of this procedure may contain the following elements:

- Responsible post or department: e.g. the shift manager in charge accepting the fuel delivery.
- For each delivery at least the following will be documented:
 - Truck number plate
 - Name of the truck's company
 - ID of the volume flow meter
 - Delivered amount
- Responsible person for checking if this truck and/or volume flow meter already has an account in the internal database
- Responsible person for checking once a month whether evidence for flow meter uncertainties has been provided by all suppliers, e.g. the latest (official) calibration certificate. If not, responsible person will request such evidence from those suppliers where evidence is missing.
- Where relevant information is stored.

Please note that this procedure must allow track to be kept of all measuring instruments involved to an extent allowing calculation of the uncertainty over the whole period and to demonstrate compliance with the required tier. If this is not achieved, the operator is required to propose alternative monitoring methods or provide justifications, e.g. unreasonable costs. For those alternatives see the answer to question 3.2.

Notwithstanding the continued need for suitable procedures, an alternative option for demonstrating compliance with the tier requirements can be achieved by providing documents clearly demonstrating

which accuracy classes are allowed to be used, e.g. contractual arrangement with the supplier demonstrating that only measurement instruments with certain accuracy classes are to be used.

3.4 Article 28(1) point b) requires comparison of at least annual results from calibration with relevant uncertainty thresholds. How can compliance be achieved here? Is it relevant who the owner of the measuring instrument is?

Article 28(1) point b) requires that *“the operator must ensure at least once per year, and after each calibration of measuring instruments, that the calibration results multiplied by a conservative adjustment factor based on an appropriate time series of previous calibrations of that or similar measuring instruments for taking into account the effect of uncertainty in service, are compared with the relevant uncertainty thresholds.”*

The procedure of complying with this requirement is described in Guidance Document 4, section 3.1.1.5 (Route CO-2b). Depending on the type of measuring instrument and the environmental conditions the uncertainty of a measurement might increase over time (drift). To quantify and to mitigate the increase of uncertainty resulting from drift an appropriate time interval for recalibration is necessary. As the result of quantification of the drift that has occurred, time series analysis of previous calibrations may also be helpful to determine the relevant calibration interval.

To take into account any further random as well as systematic errors in service, the expanded uncertainty obtained from calibration is to be multiplied by a conservative adjustment factor. The operator should determine this conservative adjustment factor, e.g. based on experience, subject to the approval of the CA. In the absence of any information or experience the use of a harmonised factor of 2 is recommended as a pragmatic yet appropriate approach.

Note that pursuant to Article 29 measurement instruments outside the operator's own control are only allowed if they at least *“allow the operator to comply with at least as high a tier, gives more reliable results and is less prone to control risks, the operator shall determine the activity data from measurement systems outside its own control”*. As a consequence, this annual check is also required for measurement instruments owned by a trading partner. However, for such cases this commercial transaction will in most cases be subject to national legal metrological control and the frequency of calibration (re-calibration) is regulated by the relevant legal text or related guidelines.

The Competent Authority has to approve this annual assessment as part of the written procedure required in accordance with Articles 58(3) and 59. The result of this annual re-assessment only has to be submitted to the Competent Authority upon request (see Article 66(2)). However, for the purpose of Article 19(1)¹⁹ of the Regulation (EU) 600/2012 on Accreditation and Verification, the result has to be made available to the verifier.

¹⁹ Article 19(1) AVR: “Where Regulation (EU) No 601/2012 requires the operator to demonstrate compliance with the uncertainty thresholds for activity data and calculation factors, the verifier shall confirm the validity of the information used to calculate the uncertainty levels as set out in the approved monitoring plan.”

4 SAMPLING & ANALYSES

4.1 Supplier data: What if the supplier does not provide sufficient information for demonstrating compliance with the required tiers?

See answer in section 3.2.

4.2 Online gas analysers: What is the (initial) validation and how can it be performed?

Article 32(2) of the MRR states: “Where online gas chromatographs or extractive or non- extractive gas analysers are used for emission determination, the operator shall obtain approval from the competent authority for the use of such equipment. The equipment shall be used only with regard to composition data of gaseous fuels and materials. As minimum quality assurance measures, the operator shall ensure that an initial validation and annually repeated validations of the instrument are performed.”

Article 32(1) requires validations for the determination of calculation factors to be carried out by applying methods based on corresponding EN standards. For the use of online chromatographs, this includes EN ISO 10723:2012 Natural gas - performance evaluation for online analytical systems. (This standard has been updated from the 1995 version that was mentioned in MRG2007 to include, among other things measurement uncertainties and assesment of errors and uncertainties of measurement of composition and gas properties).

Compared to the MRG 2007 (Monitoring and Reporting Guidelines) this gives the operator more freedom to demonstrate compliance. However, the minimum quality assurance measures for the use of online gas chromatographs, as stated in Article 32(2), is an initial validation and annually repeated validations. The approach described in section 13.5.3 of Annex I of MRG 2007 is still valid for carrying out initial and ongoing validations.

Section 13.5.3 of Annex I of the MRG 2007 stated:

“Where applicable an initial and annually repeated validation of the instrument shall be carried out by a laboratory accredited against EN ISO 17025:2005 using EN ISO 10723:1995 “Natural gas - Performance evaluation for on-line analytical systems”. In all other cases, the operator shall commission an initial validation and annual inter-comparison:

a) Initial validation

The validation shall be carried out before²⁰ 31 January 2008 or as part of the commissioning of a new system. It includes an appropriate number of repetitions of the analysis of a set of at least five samples representative for the expected value range including a blank sample for each relevant parameter and fuel or material in order to characterise the repeatability of the method and to derive the calibration curve of the instrument;

²⁰ This deadline was applicable for the MRG 2007. In the context of the M&R Regulation it should be read as „before the start of the reporting period” or “before approval of a new monitoring plan using such online gas analysers”.

b) Annual inter-comparison

The inter comparison of the results of analytical methods shall be executed once a year by a laboratory accredited according to EN ISO 17025: 2005 involving an appropriate number of repetitions of the analysis of a representative sample using the reference method for each relevant parameter and fuel or material; The operator shall apply conservative adjustments (i.e. avoiding under-estimation of emissions) to all relevant data of the respective year in cases in which a difference is observed between the results derived by the results of the gas analyser or gas chromatograph and the accredited laboratory which might lead to an under-estimation of emissions. Any statistically significant (2σ) differences between the end results (e.g. the composition data) of the gas analyser or gas-chromatograph and the accredited laboratory shall be notified to the competent authority and be immediately resolved under supervision of a laboratory accredited according to EN ISO 17025: 2005.“

This alternative initial method is quite onerous requiring at least 5 representative samples measured several times to check the “calibration curve”. The calibration curve can change significantly with time and the approach outlined in the initial validation should be adopted in the annual inter-comparison. Any statistical deviation (2σ) determined from the inter-comparison could be corrected for if an EN ISO 10723 performance evaluation or a 5 point check were performed. Laboratories carrying out the validations should be used in accordance with Article 34.

Where operators seek approval by the CA using any other approach than the one provided in the MRG 2007 the CA may evaluate the proposal in the light of the hierarchy in Article 32(1):

- Apply methods based on corresponding EN standards,
- Where such standards are not available, the methods shall be based on suitable ISO standards or national standards.

Note that section 6 of Guidance Document 5 on Sampling & Analysis provides a non-exhaustive list of such standards.

- Where no applicable published standards exist, suitable draft standards, industry best practice guidelines or other scientifically proven methodologies shall be used, limiting sampling and measurement bias.

4.3 How can it be determined whether a sample taken is “representative”?

It must be kept in mind that representativeness is of utmost importance. The following steps have to be considered:

- Analytical samples analysed in a laboratory must be representative for the samples submitted to the laboratory.
- Samples submitted to the laboratory must be representative of the batch²¹ of fuel or material they are taken from. For example, a combined sample obtained from mixing individual increments/samples must be representative; weighted instead of simple averages need to be calculated.
- Samples taken from, for example, one batch must be representative for the whole batch.

²¹ Article 3(32): “batch means an amount of fuel or material representatively sampled and characterised and transferred as one shipment or continuously over a specific period of time”

- The integrity of a sample must be maintained throughout the whole sampling and analysis process (combination of increments/samples, sub-sampling, transport and storage, analytical clean-up/pre-treatment, etc.).

Only if each step is fulfilled, representative values, i.e. valid weighted averages, can be obtained from the analyses.

The appropriate sampling approach to obtain representative samples will depend on material properties, e.g. the homogeneity/inhomogeneity of the material in terms of variability in time or space of the carbon content as well as on sampling techniques, e.g. judgemental or probabilistic sampling, minimum sample size, etc. It has to be noted that the appropriate sampling approach depends on the purpose of the analyses. Determining trace metal contaminations will lead to a different sampling approach than determining the carbon content as the main objective (see section 3.3. of Guidance Document 5 on Sampling & Analysis).

Therefore, the sampling plan for obtaining representative samples should be prepared according to fuel or material specific standards. Where such standards are not available EN 14899 for sampling waste and the supplementing technical reports CEN/TR 15310 as well as EN 15442 can be considered as suitable starting points for preparing a sampling plan. In the case of doubt or a lack of experience with the fuel or material, it is recommended to take more samples at first and then assess on the basis of analyses and growing experience whether combining samples or taking less samples per batch is appropriate without a significant loss of accuracy.

Furthermore, it is recommended to keep a sampling record documenting any deviations from the sampling plan and observations made during sampling (e.g. colour, odour,..). The sampling record, along with the “chain of custody” document that accompanies the samples that are sent to the laboratory for analysis, are all traceable back to the sampling plan. It is advisable to check with the chosen analytical laboratory that the packaging, transportation and storage procedures are appropriate to protect the integrity of the sample. CEN/TR 14310-4 is a useful source of guidance on sample packaging, storage, preservation, transport and delivery.

Please note that although those standards are suitable sources for sampling solid or liquid materials they may fail to provide proper guidance for sampling gaseous fuels. Sampling gaseous fuels is problematic since those fuels can not be stored easily. In most cases sampling is directly coupled to analysis, e.g. by the use of an online gas analyser. In particular, in the case of highly fluctuating gas flows and changes of the composition continuous sampling is required to obtain representative results (e.g. by the use of EN ISO 10723:2012 “Natural gas - Performance evaluation for on-line analytical systems”). If sampling continuously is technically not feasible or would incur unreasonable costs the proposed alternative sampling approach providing representative results can be based on e.g. proven correlations such as that a high volume flow or a specific composition occur under certain conditions during a production process or cycle.

4.4 How to proceed if the application of tier 3, i.e. analysis in accordance with Articles 32 to 35, incurs unreasonable costs?

If an operator is required to use tier 3 for calculation factors and demonstrates that the application of Articles 32 to 35 would incur unreasonable costs, the following steps have to be taken:

- Check if the application of a lower frequency of analyses than the one required by Annex VII or determined by the “1/3”-rule would still incur unreasonable costs. Note that recital 16 of the MRR requires operators to always strive to reach highest achievable tier. Therefore, even if the application of the “1/3”-rule or the incurrance of unreasonable costs results in analysing just once a year²² this may still be considered to be a more accurate and reliable monitoring approach than deferring to lower tiers since site-specific values are obtained.
Also with reference to question 1.1, it should be stressed here that only those costs that are additional to a reference system should be taken into account. This means that e.g. costs related to sampling can only be taken into account if it is not already done for other purposes. Note that costs up to 2,000 € per year (500 € for installations with low emissions) can not be considered to incur unreasonable costs. Furthermore, it has to be noted that a lower frequency of analyses may lead to a revision of sampling plan. This is because the analytical values still have to be representative of the batches or time period which samples are taken from. This makes the preparation of composite samples and sub-sampling more demanding.
- If carrying out analyses in accordance with Articles 32 to 35 and a frequency of at least once per year still incurs unreasonable costs, the operator is allowed to consider lower tiers, i.e. tier 2 or tier 1 default values.
- Only if no suitable default values are available, the operator has to propose an appropriate fall-back methodology.

²² Please note that analysing once a year must not be confused with sampling just once a year, i.e. the frequency of taking samples or increments from a batch or delivery of a fuel or material. In general a lot more samples/increments have to be taken over the year to obtain representative results.