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EFET response to Commission consultation on a planned procedural clarification in four electricity guidelines by way of a Commission Implementing Regulation

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15 June 2020

The European Federation of Energy Traders (EFET)[1] appreciates the opportunity to comment on the European Commission consultation on planned procedural clarifications to the electricity guidelines.

The proposed amendments are of a procedural nature. Although we have no fundamental concerns about these amendments, you will find below a recommendation valid for all the concerned Guidelines (GLs) to ensure a smoother and tighter process for the approval of terms & conditions and methodologies (TCMs) in case TSOs and/or NEMOs cannot come to an agreement on draft TCMs.

Articles 9.1 CACM GL, 4.1 FCA GL, 4.1 EB GL and 5.1 SO GL: we share the assessment of the European Commission that the prolongation of deadlines for the approval of TCMs, not foreseen in the CACM GL, FCA GL, EB GL or SO GL, is a reality in practice when TSOs and/or NEMOs cannot come to an agreement. Clarifying this case in the GLs is a good step. However, we would suggest setting boundaries to deadline extensions. We propose that deadline extensions be valid for a period of 6 months, with a possibility to renew them only once.

We would also recommend that NRAs or ACER, for example through amendments to article 4.4 FCA GL, or article 9 CACM GL, be introduced to consult market participants before the approval of TCMs and reflect their feedback in the final decisions.

In addition, we note that the market GLs, especially the EB GL, contain several possibilities for derogations that do not provide market participants with the forward view they need when entering into commercial agreements over several years. We recommend the Commission to limit these areas with a view to fostering harmonisation. We also recommend the Commission to increase the accountability of NRAs and TSOs with respect to timelines for implementation.

[1] The European Federation of Energy Traders (EFET) promotes and facilitates European energy trading in open transparent, sustainable and liquid wholesale markets, unhindered by national borders or other undue obstacles. We currently represent more than 100 energy trading companies, active in over 28 European countries. For more information, visit our website at www.efet.org

Furthermore, as market participants, we do have a number of additional suggestions for amendments to other aspects of the FCA and CACM GLs, which would help to ensure more effective implementation of the said rules and more efficient market functioning.

We recall that the Commission consulted market participants in early 2019 on a future review of the CACM and FCA GLs. A full review of the market GLs would be timely and beneficial. As such a review has not been launched yet, we would like to use this consultation opportunity to present our proposals. They are listed in the tables below.

We reserve our comments for further amendments to the EB GL for a later stage.

Proposed amendments to FCA GL:

Article	Suggestion	Justification
10	Add a requirement mirroring art. 21.4 CACM GL on the harmonisation of CCMs by 31 December 2020.	The concept of CCRs and regional methodologies was included in the FCA/CACM/EB GLs as a step towards full harmonisation at European level. The harmonisation of DA/ID CCMs is included in the CACM GL and should therefore, also be explicitly formulated in the FCA GL. We support the idea of harmonisation of CCMs across CCRs by 31 December 2020. However, no CCMs have been implemented in the forward timeframe so far. Article 10 could foresee that while the CCMs are being implemented, a number of no-regret harmonisation measures be taken, e.g. with regard to the input data for capacity calculation and transparency on the algorithm and inputs (such as critical network elements, remedial actions, etc). ACER could check and report on the progress towards harmonisation of CCMs in its yearly Market Monitoring Report.
16.2(a)	Modify article 16.2(a) to make it more explicit that the splitting methodology "shall **allow the market itself to decide on the splitting of capacity between timeframes in order to** meet the hedging needs of market participants"	Instead of capacity splitting, TSOs should make available to the market the maximum amount of available capacity as far in advance of real time as possible (at least one year), as per their calculation at that time, via forward transmission rights. For the avoidance of doubt, and bearing in mind that certain market participants may wish to purchase capacity only for specific months and may be reluctant to re-trade purchased yearly forward transmission rights on the secondary market, TSOs may choose to allocate the 100% of calculated capacity year-ahead not only via yearly products but also via monthly products (but a year in advance). For example, TSOs could make sole use of monthly products in the year-ahead and monthly auctions, which could be bundled into multi-month or annual blocks in the yearly auction. Further release of capacity at shorter time horizons in the forward timeframe (monthly, weekly) should be the result of capacity recalculations, or gradual release of the constraints initially applied by TSOs for year-ahead allocations when uncertainties reduce as real time gets nearer. This distinction between the timing of the auctions and the granularity of the products offered by TSOs allows the market itself, at the time of the yearly auction, to perform the splitting of capacity between yearly and monthly capacity in the most economically efficient manner (see also our comments on article 31.2).

30.1	Add a requirement in article 30.1 to consult market participants on the draft decision by NRAs to forego the issuance of LTTRs itself (in addition to the survey of market participants' needs referred to in article 30.3(a)).	Market participants are consulted on their hedging needs according to article 30.3(a). A consultation on the draft decision of NRAs would allow market participants to also give their views on the evaluation of hedging opportunities performed by TSOs and NRAs. Evidence from the April 2017 decision of the Nordic NRAs on the subject shows that NRAs can forego the conclusion of independent experts and the recommendations of the market participants survey, and at this point market participants cannot make their voice heard in the process. In April 2017, the Nordic NRAs analysed hedging opportunities in the Nordic area, where no LTTRs are issued by TSOs. In the report the NRAs commissioned to the independent consultant Houmoller Consulting, the data analysed and the experience of market participants show that the current setup of a Nordic system price and EPADs does not always provide an efficient hedge in DK1 and DK2. Both the assessment performed by Houmoller Consulting and the results of the market participant consultation point to the issuance of transmission rights by the TSOs at the DK1-SE3, DK2- SE4 and DK1-NO2 bidding zone borders as a complement to the existing EPADs. The Danish and Swedish NRAs confirmed the assessment of the independent consultant that there are insufficient hedging opportunities in DK1 and DK2. The issuance of forward transmission rights by the TSOs as a complement to the existing EPADs was the easiest remedy, supported by the majority of market participants who responded to the consultation, and which has already proven its reliability in other parts of Europe. However, for unclear reasons, the NRAs have decided not to request their TSOs to issue transmission rights according to article 30.5(a), but to request the TSOs to "make sure that other long-term cross-zonal hedging products are made available to support the functioning of wholesale electricity markets" according to article 30.5 (b). No such instruments have been developed so far (for more on this, see our point on article 30.6).
30.6	Add a requirement in article 30.5(b) foreseeing that "if the TSOs have not made available other long-term cross-zonal hedging products 12 months after the NRAs request, they shall be obliged to issue long-term transmission rights." A specific role could be given to ACER to ensure a decision according to article 30.5(b) is followed up by concrete actions.	Article 30.6 misses a compliance "penalty". The default option of the FCA GL being for TSOs to issue LTTRs, it seems only fair that if hedging opportunities are seen as missing and the TSOs and NRAs don't take action, TSOs should be obliged to issue LTTRs. In the case of the April 2017 decision of the Nordic NRAs, the NRAs requested the TSOs to "make sure that other long-term cross-zonal hedging products are made available to support the functioning of wholesale electricity markets" according to article 30.5 (b). Article 30.6 requires such alternative instrument to be developed by TSOs within 6 months and implemented within another 6 months (12 months in total following the NRA decision). Three years later, the TSOs have not proposed any alternative to the existing framework.

31.2	Modify article 31.2 to reflect the reality of capacity calculation and allocation, as follows: "All TSOs issuing long-term transmission rights shall offer long-term cross-zonal capacity, through the single allocation platform, to market participants for at least annual monthly time frames, **irrespective of the time at which the allocation of this capacity takes place**. All TSOs in each capacity calculation region may jointly propose to offer long-term cross-zonal capacity on additional time frames."	Article 31.2 introduces confusion between the timing of the auction and the timeframe for which LTTRs are made available to the market. There is never any assurance, whichever the TSOs' splitting methodology, that long-term capacity will be available for monthly auctions following month-ahead recalculations. What is important (see our comments on article 16), is that once capacity is made available to the market in the year-ahead auction, market participants can choose to buy capacity for single months or bundle it per year. Our proposal for article 16 of letting the market decide on the split between yearly and monthly capacity does not say anything else: it will be up to the market to decide the proportion of monthly vs. yearly capacity that is needed. Our only call is to make sure that this happens as soon as the capacity is calculated (i.e. for the auction in Y-1), and that the choice is given to market participants to decide how to divide capacity at that moment. Additional monthly capacity would then be released at each monthly recalculation of capacity, if deemed available for the market. This distinction between the timing of the auctions and the granularity of the products offered by the TSOs allows the market itself, at the time of the yearly auction, to perform the splitting of capacity between yearly and monthly capacity in the most economically efficient manner.
34	Delete article 34 foreseeing the possibility for TSOs to issue FTR obligations.	When issuing FTRs, TSOs get the congestion revenue in case the request for capacity (with the price > 0) is higher than the available capacity at each allocation. In case the spread is in the opposite direction, we do not see the rationale for paying a negative spread to TSOs (which is the case for FTR obligations, not FTR options). Considering that caps can be introduced by TSOs on the remuneration of curtailed LTTRS according to article 54 (and all TSOs have done so), there is no financial risk for the TSOs in allocating capacity. FTRs as obligations would only make sense if market participants would trade between themselves such or similar contracts and payment for the negative spread would be the consequence of risk premiums. This is however not the case when TSOs allocate capacity.
40	Add a sentence in article 40 forbidding the application of a reserve price in auctions for the allocation of LTTRs	The use of a reserve price in long-term auctions prevents the market from establishing an efficient clearing price – i.e. where the auction price of the capacity reflects the true market valuation of capacity rather than a value pre-ascribed to it by a TSO or a cable operator. As of 2020, we note that BritNed is the only bidding zone border in Europe where a reserve price for the allocation of capacity still applies. There is a need to clarify European legislation to ensure that this situation is remedied.

53.1	Delete the reference to "ensuring operations remain within operational security limits" as a possible reason for TSOs to curtail FTRs.	Curtailment of long-term transmission rights to ensure operations remain within operational security limits should only apply to PTRs. FTRs cannot be nominated, so their allocation cannot have any impact on the state of the system, and TSOs bear no physical risk linked to their allocation. Therefore, we do not see any reason to have a possibility of curtailment for system security reasons in the case of FTRs. Only curtailment for Force Majeure should apply to both PTRs and FTRs (e.g. for IT system failure).

Proposed amendments to CACM GL:

Article	Suggestion	Justification
4.6(a)	Delete article 4.6(a) foreseeing the possibility for Member States to have monopoly NEMOs.	We fail to understand why such an exception still exists. This goes against the principle of fair competition between private undertakings as laid out in the Treaty, and of NEMO competition in particular, as laid out in the CACM GL. Hence, we propose that this exemption is removed from the CACM Guideline unless Member States can demonstrate that it provides welfare benefits. In its May 2018 report on NEMO competition, the European Commission notes: "Where monopolies are established, trading opportunities in terms of platforms, innovative products and close to real time trading to allow further integration of renewable sources appear to be more limited." The report does not identify any reason why 9 Member States apply the monopoly NEMO model. Hence, we understand that the monopoly model does not have any proper justification, nor is it beneficial for social welfare. However, no recommendation is included in the report on the future of this model. Article 5.3 CACM GL states that "if the Commission deems that there is no justification for the continuation of national legal monopolies or for the continued refusal of a Member State to allow cross-border trading by a NEMO designated in another Member State, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within Member States." We believe it is time to act accordingly.
5	Delete the full article 5 detailing the conditions for the designation of monopoly NEMOs.	See comment to article 4.6(a).

7.1(f)	Add a sentence in article 7.1(f) requiring the publication of aggregated bid/offer curves per bidding zones by all NEMOs active in each bidding zone.	All NEMOs active in a bidding zone should publish common aggregated (and anonymised) bid/offer curves based on orders of all participants in the day-ahead market. Indeed, without aggregated bid/offer curves taking account of all orders submitted to all the NEMOs of each BZ, market participants cannot properly understand market fundamentals. Exception for special cases could be foreseen. More details at: https://efet.org/Files/Documents/Downloads/EFET_MNA%20Day%20Ahead%20bid%20offer%20curve_17042020.pdf
14.4	Include in article 14.4, as a minimum requirement, the precise timings for capacity (re)calculation in intraday foreseen in the ACER Decisions 01-2019 and 02-2019.	The adoption of capacity calculation methodologies (CCM) for intraday according to the CACM GL requirements has been a lengthy process. At this stage, most regions have adopted their CCM, but how, how fast, and how frequently calculation and recalculations of cross-zonal capacities will be performed in intraday remains unclear. The ACER Decision of 21 February 2019 recommends, for the Core region, that capacity calculation and recalculation for ID is carried out at least in accordance with the required auction schedule - first calculated by ID CZ GOT (i.e. 15:00 D-1), using the cross-zonal capacity remaining from the day-ahead timeframe, then at 22:00 D-1, and later at 10:00 on the delivery day. We call on TSOs to implement these requirements. Paragraph (52) of the ACER Decision of 24 January 2019 on intraday capacity pricing seems to recommend these deadlines for the whole SIDC area.
21.1	Add a point (d) requesting a framework for transparency in the CCMs.	Transparency of capacity calculation (algorithm, inputs, outputs) is necessary for market participants to appropriately understand how capacity calculation works, and how changes in market fundamentals affect available capacities. This is necessary to allow market participants to forecast day-ahead market results to the best of their abilities, and take appropriate actions (trading in general, including hedging; investment) in the forward timeframe. The ACER Decision 02-2019 on the Core DA CCM foresees such a transparency framework. All CCMs should include such detailed provisions. Further information on DA flow-based transparency can be found in the framework of CWE and Core CG discussions.
21.2	Include in article 21.2, as a minimum requirement, the precise timings for capacity (re)calculation in intraday foreseen in the ACER Decisions 01-2019 and 02-2019.	See comment to article 14.4
21.4	Enforce the timing for the use of harmonised CCMs across all CCRs.	We support the idea of harmonisation of CCMs across CCRs by 31 December 2020. However, not all CCMs have been implemented in DA and ID so far. Article 21.4 could foresee that while the CCMs are being implemented, a number of no-regret harmonisation measures be taken, e.g. with regard to the input data for capacity calculation, transparency on the algorithm and input

		(such as critical network elements, remedial actions, etc). ACER could check and report on the progress towards harmonisation of CCMs in its yearly Market Monitoring Report.
26.5	Add a requirement in article 26.5 for TSOs to report not only the location, amount and justification for reductions during the validation process, but also on the economic efficiency of the reductions, and their plan to remedy the situation in case the decision was necessary but economically inefficient.	Cross-zonal capacity reductions during the validation process deviate from the standard capacity calculation methodology, which itself is expected to provide an optimum between capacity made available to the market and operational security. Making the economic assessment of the reductions during the validation process would allow all involved parties to assess whether these reductions were the right tools, or whether amendments to the capacity calculation method itself are necessary.
32-34	Articles 32 to 34 should be reviewed following the adoption of the CEP.	Some of the elements of articles 32 to 34 have been covered in article 14 of the recast Electricity Regulation 2019/943. Our preferred option would be to amend these articles to mirror Regulation 2019/943. Another option would be to remove them altogether, as article 14 of the Electricity Regulation is fairly detailed.
35	Article 35 should mirror art. 21.4 by requiring the harmonisation of RDCT methodologies by 31 December 2020. Article 35 should be reviewed following the adoption of the CEP.	The concept of CCRs and regional methodologies was included in the FCA/CACM/EB GLs as a step towards full harmonisation at European level. The harmonisation of DA/ID CCMs is included in the CACM GL and should therefore, also be explicitly formulated for RDCT methodologies. Some of the elements of article 35 have been covered in article 13 of the recast Electricity Regulation 2019/943. Our preferred option would be to amend these articles to mirror Regulation 2019/943, as article 13 of the Regulation lacks the practical details of article 35 CACM GL.
36.3	Add a requirement in article 36.3 that the back-up methodology should include explicit cross-border fallback auctions.	Unlike SDAC where the back-up methodology foresees the organisation of explicit fallback auctions, in SIDC, there is no cross-border fallback measure. In case XBID fails, the only fallback option is the reliance on local intraday markets, and no cross-border transmission capacity is offered to the market. The back-up methodology should require TSOs to organise explicit fallback auctions in ID to ensure that the market can access transmission capacity in intraday.
41.1	Article 41.1 should be amended to ensure compliance with article 10.2 of Regulation 2019/943 and include an automatic readjustment mechanism that would allow the technical price limit in day-ahead to effectively reflect the VoLL.	Thanks to the ACER Decision of 14 November 2017, the regulatory framework for day-ahead technical price limits matches the requirements of article 10.2 Regulation 2019/943. This amendment is only to reflect the change in the Electricity Regulation.
53.3	Specify that as of 1 January 2021 the standard market time unit for the whole SIDC should be aligned on the 15-minute ISP, as per article 8.4 of the recast Electricity Regulation 2019/943.	Full harmonisation should include 15-minute ISP, 15-minute cross-border granularity (gates) and 15-minute granularity of tradable products. Due attention, of course, should be given to the performance of the intraday coupling algorithms to ensure coupling operations remain at least at the same level of reliability as today. A feasibility study with respect to cross-product matching on continuous trading between the

		moment 15-minute products are introduced and all ISPs are harmonised to 15 minutes should be carried out.
54.1	Article 54.1 should be amended to ensure compliance with article 10.2 of Regulation 2019/943 and include an automatic readjustment mechanism that would allow the technical price limit in intraday to effectively reflect the VoLL.	In its Decision of 14 November 2017, ACER sets a technical price limit of +/- 9,999 EUR/MWh for SIDC. The intraday technical price limits, however, do not foresee an automatic readjustment mechanism when prices come close to the limit, as is the case for day-ahead price limits. This is not in line with article 10.2 of Regulation 2019/943.
55.2	Article 55.2 should mirror art. 63.2 and foresee that continuous trading should not be interrupted by more than 10 minutes for capacity pricing auctions.	Ideally, intraday auctions should not be implemented in parallel to continuous trading, as their harmful impact on the liquidity of the continuous market would outweigh considerably their suggested advantages. We, nonetheless, take note of ACER's Decision from 24 January 2019 to introduce three pan-European auctions to complement continuous trading. However, the interruption time that the pan-European auctions would cause to continuous trading needs to be reduced to 10 minutes maximum. Article 55 does not give any detail as to how intraday capacity pricing auction(s) should be organised, and what the limits are of the effect they can have on XBID. Article 63, on the other hand, clearly states that complementary regional auctions "shall not have an adverse impact on the liquidity of the single intraday coupling" (art. 63.4.a) and that "continuous trading within and between the relevant bidding zones may be stopped for a limited period of time […] which shall not exceed the minimum time required to hold the auction and in any case 10 minutes" (art.63.2). The provisions of article 63, which was discussed much more in depth during the negotiations on the CACM GL, should be integrated in article 55. We believe that (an) intraday capacity pricing auction(s) should not lead to an interruption of continuous trading of more than 10 minutes. This will ensure that the market design truly respects the letter and spirit of CACM, where intraday capacity pricing is a complement to continuous trading, not the contrary.
59.4	Add an explicit requirement in article 59.4 that cross-border capacity shall be made available to the market as of the ID CZ GOT, as per the definition of intraday cross-zonal gate opening time at point 38 of article 2.	The definition of intraday cross-zonal gate opening time as per point 38 of article 2 says that capacity is "released" at that moment in time. Although ACER has set the cross-zonal intraday GOT to 15:00 (CET) D-1 for the whole of Europe, many TSOs in Continental Europe do not offer capacity until much later – e.g. up to 22:00. We oppose this reading of the CACM GL and the ACER Decision, resulting in a CZ GOT in name only and circumventing the ACER Decision. Article 59.4 should include an explicit requirement that at least the capacity left from the DA

		timeframe should be offered at the GOT, if TSOs' calculations allowing for new capacity to be offered have not been completed yet.
59.4	Add an explicit requirement in article 59.4 that intraday trading shall be based on shared order books as of ID CZ GOT.	To improve liquidity on the market, we request the sharing of order books by all NEMOs from the official CZ GOT set by ACER at 15:00, in line with the requirement that order books should be shared for the whole duration of SIDC. Local technical or regulatory hurdles to this should be removed to ensure full compliance with the ACER Decision.
59.4	Add an explicit requirement in article 59.4 to extend the sharing of order books by NEMOs after ID CZ GCT, until local ID GCT.	For the sake of improving liquidity throughout the ID timeframe, including at local level, it would be important to extend the sharing of order books until local ID GCT. The benefits of cross-border intraday trading closer to delivery are higher in cases of structural differences in the generation mix on each side of a border. This applies, for example, to borders with large shares of wind generation on one side and large shares of hydro generation on the other. Where local ID GCT is already 15 or even 5 minutes before delivery, and as market design evolves in other places towards extending the ID market closer to real time, continued sharing of order books until local ID GCT would be particularly beneficial.
64	Include a principle that explicit capacity allocation in ID is to be favoured compared to no capacity allocation at all.	We currently experience cases where TSOs/IC operators and NRAs argue that explicit auctions for cross-zonal capacity is not in line with the CACM GL, whereas there is no prospect to implement implicit allocation in the short to medium term. It should be made clear in the CACM GL that though implicit allocation of ID capacity is the target, TSOs and NRAs should ensure that capacity is allocated by any other mean, as long as implicit allocation is not a possibility.