EFET European Federation of Energy Traders
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Amstelveenseweg 998
1081 JS Amsterdam

+31 20 520 7970
secretariat@efet.org
www.efet.org

European Commission consultation on the establishment of the annual priority lists for the development of network codes and guidelines for 2019 and beyond

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EFET response – 25 January 2019

We thank the European Commission for the opportunity to comment on their annual priority lists for the development of network codes and guidelines for 2019 and beyond.

1. Priorities for 2019

We agree with the Commission proposal to focus on the implementation of the existing Network Codes and Guidelines for 2019.

On the electricity side, the implementation of the market Guidelines is not completed. Implementation of the Forward Capacity Allocation (FCA) and Capacity & Congestion Management (CACM) Guidelines (GLs) is progressing slowly, notably due to the fact that many implementation methodologies drafted by the TSOs have required NRAs to request amendments, and sometimes to refer them to ACER for a final decision. The implementation of the Electricity Balancing (EB) GL is only beginning and will likely last until 2025.

Focusing on the implementation of the Guidelines however does not prevent learning lessons already that could improve and facilitate implementation. We see inefficiencies in the way certain methodologies are being developed by TSOs (or NEMOs as the case may be) with many of them ending up referred to ACER (capacity calculation regions, capacity calculation methodologies, technical price caps in the CACM Guideline). We see also a very lax attitude of certain regulators when it comes to monitoring the implementation of the Guidelines (e.g. application of article 30 of the FCA Guideline in Italy and the Nordic area). The implementation phase would be improved with a greater involvement of the Commission at all stages of the process.

On the gas side, progress on implementation of network codes varies significantly across Europe, and priority should be given to areas where implementation is lagging. Moreover, first lessons could be learned from the first applications on the TAR NC voted in March 2017 that should be implemented by Member-States by April 2019.

2. Priorities for 2020 and beyond

a. Amendment proposals to existing Network Codes and Guidelines

On the electricity we would like to suggest a number of amendments to the existing market Guidelines:

i. Forward Capacity Allocation Guideline (FCA GL)

Article	Suggestion	Justification
10	Mirror art. 21.4 CACM GL requiring 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.
16	Instead of capacity splitting, the TSOs should make available to the market the maximum capacity available as far in advance of real time as possible (at least one year), as per their calculation at that time, via forward transmission rights. 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 the TSOs for year-ahead allocations when uncertainties reduce as real time gets nearer.	Our position of advocating maximisation of capacity allocation as far from real time as possible, with recalculation at shorter time horizons in the forward timeframe is based on the following principles: (1) economic efficiency at the time of allocation and (2) allocating all the capacity year-ahead as per calculation at that time and recalculation/release of constraints for monthly and/or weekly products ensures that TSOs do not unnecessarily sit on hedging possibilities that could be valued on the market. Maximisation of capacity allocation as far from real time as possible and recalculation at shorter time horizons would benefit TSOs, market participants and, ultimately, consumers.

30	Strengthen the criteria for deviations from the obligation for TSOs to issue long-term transmission rights and give ACER the role to supervise the follow-up on NRA decisions on that matter.	Experience from the April 2017 decision of Nordic NRAs on the subject: in the report commissioned to Houmoller Consulting by the NRAs, the data analysed and the experience of market participants show that the current setup of 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 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 is also 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, they 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). Article 30.6 requires such alternative instrument to be developed by the TSOs within 6 months. A year and a half later, the TSOs have not proposed any alternative to the existing framework.

34	Delete 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 the TSOs (which is the case for FTR obligations, not FTR options). There is no financial risk for the TSOs in allocating capacity. Furthermore, 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.
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 not apply to FTRs, as they cannot be nominated and hence have no impact on network flows; only curtailment for Force Majeure should apply to both PTRs and FTRs.

ii. Capacity Allocation and Congestion Management Guideline (CACM GL)

As a general observation, we note that the regional methodologies developed for in the different capacity calculation regions (CCRs), such as Capacity Calculation or Redispatch and Countertrading, lack proper coordination. The concept of regional implementation was introduced at a rather late stage in the drafting of the CACM GL, but with the intention that it be a step towards European harmonisation. The significant discrepancies we can now observe between the different regional methodologies risk, in effect, hindering the harmonisation of methodologies at European level, as intended in the Guideline.

Article	Suggestion	Justification
4.6	Delete the possibility for Member States to have monopoly NEMOs (hence also delete art. 5).	We fail to understand why such an exception 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.
26	TSOs should report on reductions during the validation process, their economic efficiency, and their plan to remedy the situation in case the decision was necessary but economically inefficient.	

32-34	To be reviewed following the adoption of the CEP.	Some of the elements from the CACM GL have been taken over in article 13 of the draft recast Electricity Regulation. Need to assess what is in the main Regulation and can be removed from CACM, and what needs to stay.
35	Mirror art. 21.4 by requiring the harmonisation of RDCT methodologies 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 for RDCT methodologies.
41/54	The ACER decision on price caps (provided that our suggestions on applying the same principle in DA and ID is supported) could be integrated directly in the GL.	
55	Mirror art. 63.2 and foresee that continuous trading should not be interrupted more than 10 minutes for capacity pricing auctions.	Article 55 does not give any detail as to how intraday capacity pricing auction(s) should be organised, and what are the limits of the effect they can have on XBID. Article 63 on the other hand clearly states that complementary regional auctions 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. The current proposal of TSOs to suspend XBID during 45 minutes (15 minutes prior, and 30 minutes after the auction(s)) is absolutely not acceptable. We believe that 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. Moreover, article 63 should explicitly include provisions relating to the coherence of the different regional/national intraday models with the intraday capacity pricing model under article 55. Therefore, regional auctions under article 63 should be limited in number and coincide by the pan-European auction(s) of article 55, while at all time ensuring that their effect on continuous trading is limited to the maximum. Harmonised bidding and nomination rules should apply in all bidding zones.
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 (*cf.* NEMO Link case). 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.

iii. Electricity Balancing Guideline (EB GL)

Article	**Suggestion**	**Justification**
30.1 (a)	Clarify that marginal pricing refers to the highest-priced bid that was activated during the relevant Imbalance Settlement Period	The EB GL leaves room for interpretation regarding the notion of “marginal pricing”. This inaccuracy allows unwelcomed constructs such as an optimization cycle (OC) balancing pricing period (BEPP) as proposed for the aFRR implementation framework. The OC BEPP would significantly increase the complexity towards market participants (225 prices per ISP, more than 150,000 per week) and reduce visibility in balancing energy price formation. It would also not reflect any market timeframe in which market participants can take action. And it would blur the connection with imbalance

		settlement by making in the end the balancing energy pricing much closer to a Pays-as-Bid than a Pay-as-Cleared (marginal pricing) scheme. "Marginal pricing" should be clearly defined as the highest-priced bid that was activated during the relevant Imbalance Settlement Period.
30.1 (b)	Clearly state that the activation of balancing energy bids activated for purposes other than balancing should not affect the balancing energy price. It should also be clarified that bids that should have been activated for balancing purposes according to the merit order but that were prevented from activation due to system constraints should be compensated for the opportunity loss.	The current wording of the EB GL only warrants that energy bids activated for congestion management shall not set the marginal price of balancing energy, which means that only marginal bids that are used for congestion management will be scrutinised by the TSOs to ensure they do not set the marginal price of balancing energy. We believe that all bids in a joint congestion management / balancing merit order list that are used for congestion management should be scrutinised, in order to assess their effect not only on the marginal price of balancing energy, but also on the imbalance settlement price. Only this will ensure that system balancing costs and congestion management cost are properly allocated, the former being borne by BRPs, and the latter being socialised via network tariffs. Hence, we request the reinsertion of the wording of an earlier version of the EB GL, which foresaw that *"if balancing energy bids are activated for purposes other than balancing, the price of these activated balancing energy bids shall not determine the imbalance price and shall not set the price of balancing energy"*. Furthermore, bids that should have been activated for balancing purposes according to the merit order but that were prevented from activation due to system constraints should be compensated for the opportunity loss. The continuation of this damaging practice is harming the fundamentals of the market and continues to blur signals for both the balancing market and congestion management.

30.2	Remove the possibility for TSOs to introduce price limits for balancing energy pricing, both for bidding and clearing.	In order to allow the balancing market to function optimally, free pricing of balancing energy bids is essential. Only this way can the right price signals be propagated throughout the various market timeframes and help identify, as the case may be, scarcity or surplus. EFET has been advocating the removal of artificial price caps and floors consistently in the past, and we therefore welcome this explicit prohibition in the Balancing Guideline. We request the suppression of Art. 30.2 and the reintroduction of the wording of the October 2016 versions of Art. 19.3(d) *(“The terms and conditions for balancing service providers shall: […] not impose any floors or caps below the value of lost load on balancing energy prices, including bidding and clearing prices”*) and Art. 47.2 *(“Balancing energy prices, including bidding and clearing prices, shall not be floored or capped below the value of lost load.”*), in order to prohibit caps and floors both on bidding and clearing prices. As a means of example, it should be noted that some Member States have already gone around the principles of the EB GL to introduce balancing energy bidding price limits. As the EB GL does not explicitly refer to bidding limits, the implementation of such limits does not require a harmonisation between all TSOs and can be introduced unilaterally. Such bidding limits implicitly cap balancing energy price clearing (and imbalance settlement), against the principles for the EB GL. Explicit and implicit regulated price caps and floors should be removed in all market timeframes. This is a firm commitment of a number of European governments, as per the Joint Declaration for Regional Cooperation on Security of Electricity Supply in the Framework of the Internal Energy Market signed by 12 European governments on 8 June 2015. Regulated price caps serve

		no other purpose than shielding end-consumers from unexpected price caps. This, however, comes with the assumption that end-consumers would be fully exposed to volatility in the market. Decision-makers should not be scared of increased price volatility and the occurrence of price spikes. Natural volatility of the markets does not lead to higher risks for the system or higher prices for end consumers, provided that these customers are fully aware of market risks and are able to use the appropriate hedging instruments available, or to outsource these activities. It is indeed important to note the complementary role of future/forward products and hedging practices (including of optional products, already available with the existing market design as any other type of energy products) for limiting the impact of price spikes occurring in the short-term markets. Meanwhile, most electricity is bought and sold in forward markets and we would normally expect projections of tighter supply-demand conditions to incentivise more forward contracting. Trading of more sophisticated forwards and options will flourish after volatility is seen to transpire in the market. In any case, only a very small proportion of total demand is affected by price spikes and these costs are faced by supply businesses rather than being seen by customers themselves. Moreover, capping prices for suppliers (and other wholesale market participants) will result in inefficiencies and thus result in higher prices for customers in the long term. Some price limits may however need to be introduced by market operators (power exchanges) for technical reasons in DA and ID, e.g. to set a limit for price-taking orders and for collateral calculation. This is ruled in the CACM GL. For the balancing timeframe, no such reasons apply.

38-42	Delete the possibility for TSOs to reserve transmission capacity for balancing purposes.	Cross-border reservation of transmission capacity for balancing purposes poses a risk to the previous trading timeframes. The concept has been rebranded in Art. 38 to 42 of the EB GL, but its effect remains the same: by allocating transmission capacity specifically for use in the balancing timeframe, TSOs remove available capacity from the allocation in the other timeframes, thereby restricting market participants' ability to adjust their position across borders in the most economically efficient manner. The use of cross-border transmission capacity is a key element in the European market integration of forward, day-ahead and intraday timeframes. A major objective of integration projects such as the EU Harmonised Allocation Rules for forward transmission rights, day-ahead flow-based market coupling and the future platform for implicit cross-border intraday trading are to improve the access and use of such transmission capacity. In its last version, the Balancing Guideline would turn the clock back on those improvements. EFET strongly recommends that all cross-border transmission capacity be available to the market, and that the different options for TSOs and DC cable operators to reserve transmission capacity for balancing purposes in Art. 38 to 42 be removed from the Guideline. Should TSOs require cross-border transmission capacity for balancing purposes that they have already sold, they should buy back this capacity from the market at a price that reflects its true value at that moment.
52.2 (d)	Delete the possibility for TSOs to apply dual pricing for imbalance settlement.	The option that remains in the draft for TSOs to propose dual pricing for imbalances is prone to maintaining inefficient price signals from the balancing timeframe. Dual pricing has the potential to blur the price signals emerging from the balancing market, and runs the risk to create a barrier to

		entry for new entrants or market participants with small portfolios. It may also be a deterrent to the application of balancing responsibility for intermittent renewable energy sources in view of their full integration into the market. EFET therefore asks the removal of the dual pricing option from article 52.2(d) (and art. 18.7(g)). For harmonization purposes, we would like to put forward the idea that only balancing energy prices should be used to define the imbalance settlement price. The methodology to combine the balancing energy prices of the different standard products harmonised at EU level and the local specific products into the imbalance settlement price should be harmonised..

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b. *Reaction to the proposed development of Network Codes and Guidelines*

On the electricity side, we note that the recast Electricity Regulation (part of the Clean Energy Package) foresees more details in the elements to be included in the NCs/GLs going forward in its article 55. We do support the greater level of detail included in the recast Regulation.

We also support the deletion by the trilogue parties of points (l) and (p) of the initial proposal of article 55, which foresaw the possibility for the European Commission to adopt specific codes on energy efficiency and regional operation centres (now regional coordination centres):

- energy efficiency is ruled by a separate Regulation,
- regional operation centres (now regional security coordinators) operational rules, at least in their general principles, are laid out directly in the draft recast Electricity Regulation (art. 32 and following).

However, we deeply regret the reinsertion of point (n) in article 55 that foresees the possibility to develop specific network codes for demand response and energy storage. The market rules applying to operators engaging in demand response or storage should be exactly the same as for any other market participant; if any of these rules impede, directly or indirectly, operators engaging in demand response and/or storage from accessing the market, they should be amended directly in the market Guidelines (FCA, CACM or EB GLs).

On the gas side, EFET underlines the major importance of the set of studies that the European Commission will perform over the year 2019 as preparatory work for a future Gas Package. The identified issues of the current gas market design that should be investigated are the following ones:

- Discarding of license constraints that uselessly hampers market functioning (both for wholesale trading and management of storage and of bundled transport capacities).
- Proper definition of the respective roles of regulated versus market entities in competitive & contestable activities, in particular in the context of new gas technologies development;
- Smart support that allows the development of renewable and decarbonized gases but avoids distortions to the market;
- Future risks of assets stranding and potential collateral tariff pancaking effect;
- Capacity / commodity release schemes, especially in regions where there is a lack of competition or market liquidity;
- Increased coordination between gas and power infrastructures for grid planning and investment projects;

Moreover, it is not yet clear whether these issues should be treated through the development of Network Codes and Guidelines, or whether other legislative instruments should be used.