EFET European Federation of Energy Traders

# EFET response to ERGEG's draft Framework Guidelines on Capacity Allocation and Congestion Management for electricity

## *Introduction*

EFET welcomes the draft framework Guidelines. They will be of crucial importance in shaping the development of European electricity markets. The draft Guidelines, for the first time, clearly set out a number of key requirements for the good functioning of cross-border competition:

- Liquid wholesale markets
- Firm, longer maturity, cross-border transmission products issued by TSOs and tradable by market participants
- Consistency of capacity allocation in different timeframes
- Coordinated allocation of a maximum volume of transmission capacity in different timeframes across the whole Europe
- One European day ahead price coupling
- Accessible and competitive intraday markets

Once these elements are in place, it will be possible to describe the European wholesale power market as truly integrated and allowing for competitive entry. These changes should ensure that cross-border capacity is efficiently allocated across all timeframes, including the forward market.

However, the benefits go much wider than this. In particular, dynamic efficiency will be improved by ensuring appropriate signals are present to aid investment decisions. Market participants will also see basis risk reduced, if they are able to more closely hedge cross-border positions. Such hedging requires that the underlying transmission capacity product sold by TSOs better matches their needs. This will, in turn, also ensure proper cross-border retail competition being able to take off, as it will allow producers to manage their portfolios across the whole continent over the appropriate 1-3 year timeframes for which supply contracts are typically concluded. Finally, proper price signals for re-purchase of transmission rights and compensation for curtailment of cross-border capacity should help establish a liquid market in transmission capacity products to match the electricity commodity market. These signals will in turn enable TSOs to take more efficient network management decisions, and Regulators to implement incentive based regulation of TSOs' congestion management practices.

<u>We do, however, believe there are some parts of the draft Guidelines that should be improved. We group the desirable improvements under three main</u>

headings, which are set out below. We have answered the specific ERGEG questions in the attached Annex.

### i. Clarify and expand obligations and avoid ambiguity

The codes on capacity allocation, capacity calculation, and congestion management for electricity will be drafted by ENTSO-E. We cannot expect that TSOs will voluntarily fetter their own business discretion when constructing such codes. The European codes will result in binding rules and will to an extent supersede existing national codes and rules. Whereas market participants enjoy legal security (e.g. rights to appeal decisions of NRAs) in national rulemaking processes, this legal security is absent in the European code process. This means that the framework Guidelines, as constructed by Regulators, need to be very concrete and clear about TSO duties, obligations and discretions (where appropriate). Otherwise market participants could have no confidence that the related codes will be developed to meet the requirements of the market and will accord with the expectations of Regulators. The framework Guidelines also need to be clear about relations between the European codes and national codes to avoid ambiguities.

Furthermore, we would expect the Guidelines to deal comprehensively with all matters related to transmission capacity calculation and allocation, and methods already touched on in the underlying Regulation 714/2009, in such a manner that national Regulators and ACER can rely on them for enforcement purposes.

The framework Guidelines should be drafted in a manner consistent with the legal basis of Regulation 714/2009. The fact is that the existing Congestion Management Guidelines have rarely been properly implemented nor enforced inside national jurisdictions. Thus, it will be of crucial importance that Regulators will not only draft the new Guidelines correctly, but also insist on full implementation of them by TSOs from the time when they enter into force. In the meantime, we trust that Regulators focus on enforcing implementation of the existing Congestion Management Guidelines.

### ii. Minimise the risk of regional and national deviations from the Guidelines with strict time limitations

EFET believes that solutions need to be consistent around Europe. The new Guidelines should not allow scope for national or regional markets to continue, with design features or rules as variations around the target model. For example, under the Guidelines, Nordic TSOs should no longer enjoy discretion to refrain from allocating forward transmission rights, and Iberian exchanges should no longer be permitted to monopolise the intraday market through their organisation of implicit auctions.

At several points in the Guidelines reference is made to national considerations or the role of national Regulators (for example: Articles 1.1.5, 1.2.3, and 1.2.6.). EFET believes such references will be inappropriate in final binding network codes, which will have direct effect at European level. The Guidelines as drafted so far largely fail to refer to the role of the Agency (ACER) which is set out in the applicable EU legislation and has been given specific duties with respect to cross-border energy infrastructure. Furthermore EFET believes that it will be difficult – if not impossible - to separate national from cross-border aspects of capacity allocation and congestion management, given the interdependence of network flows.

### iii. Distinguish between monopoly and competitive functions

The Guidelines should avoid prejudicing the outcomes of competitive and market processes or unnecessarily extending the monopoly elements of system operation. A key issue in this respect is the nature of the relationship between TSOs and power exchanges, the governance of that relationship, and the responsibility for, and ownership of, any shared algorithms that need to be developed with respect to day ahead and intraday allocation.

EFET considers that this relationship between TSOs and exchanges for Day ahead and intraday must be at arm's length, based on a clear definition of respective roles and responsibilities on the Capacity Management Module (CMM) and on the Shared Order Book (SOB), or market coupling function.

As a general principle, TSOs will be the customers in charge of the CMM (coordinated calculation and publication of the available capacities and continuous knowledge on the use of these capacities) and in charge of writing the specifications for the allocation mechanism, in close coordination with representatives of the market participants. Power exchanges will be invited to propose a cross-border matching algorithm, which will comply with the implicit allocation and, if needed, with additional functionalities that may be requested.

The cross-border platforms in charge of running the cross- border matching algorithm should be open and allow convergence and integration at European level. The single price calculation algorithm for day ahead market coupling must be publicly available to ensure confidence and transparency. The same should apply to the shared order book function (SOB) used for intraday bids and any algorithms associated with it. Regulators should be monitoring and ensuring standardisation, openness, transparency and cost efficiency of any monopoly elements.

Also, in this introduction, we wish to raise the subject of the existing Congestion Management Guidelines and the continuing ERIs.

Existing market linking projects at both national and regional level should be encouraged, provided that they do not delay the implementation of the target model or coordination at regional level, and with a specific attention to make sure that intermediate steps do not bring any potential threat to existing markets.

A specific attention also needs to be given to intermediate steps, such as temporary tight volume coupling, or coupling solutions over cables excluding any allocation of forward transmission rights. Such steps, while, apparently progressive may pose a threat to existing market liquidity and stability.

Competition between projects and the objective of fast implementation could induce adverse impacts on existing markets (especially in the case of exclusive solutions Proposed interim solutions must be properly tested and consulted on. Consultation of market participants should help detect and correct unnecessary risks and impacts.
The projects that clearly need to go forward include:

- Price coupling within and between existing regions
- Cross border development of intraday markets,
- Coordinated allocation of firm, longer maturity transmission capacity rights by TSOs between all bidding zones.

*Annex*: Replies to specific questions

EFET has, in addition to comments above, and replies to specific questions, drafted corresponding amendments to the Guidelines as presented by ERGEG. We hope to discuss our ideas for amendments in bilateral meetings over the next months.

***ANNEX: REPLIES TO SPECIFIC QUESTIONS***

***General Issues***

*1. Are there any additional issues and / or objectives that should be addressed in the Capacity Allocation and Congestion Management IIA and FG?*

Yes, indeed several issues are clear in the existing Regulation and Congestion Management Guidelines, but not properly addressed in the new Guidelines, including:

- Duty of TSOs to maximise the volume of transmission capacity allocated cross-border, and of Regulators to ensure maximisation cross-border
- Obligation for TSOs not to discriminate against cross-border transactions when establishing congestion management processes and rules inside their own control areas, and duty of Regulators to actively monitor this type of potential discrimination
- Rule that transmission capacity rights issued by TSOs must be as firm as possible; and that, to the degree they are firm, a TSO is not allowed to curtail allocated capacity except in the case of *force majeure* or emergency situations; if no emergency situation or *force majeure* has occurred (such as when there is sufficient time to manage the situation), any restriction of transmission rights already granted should proceed by way of a TSO voluntary repurchase mechanism.

Two other matters could usefully be addressed by the CACM Guidelines:

- Removal of all non- harmonised requirements and specific national laws that could hamper participation in auctions: any additional regulatory requirement, and notably if it limits participation, should have a clear impact analysis on how it affects competition and the efficient allocation of capacity rights
- Preclusion of non-harmonised national constraints on ramping rates, particularly over DC cables

*2. Is the vision of the enduring EU-wide target model transparently established in the IIA and FG and well suited to address all the issues and objectives of the CACM?*

No. We believe that some aspects of the EU wide target model have to be described in more detail, to ensure that there will be a common understanding and a consistent implementation in all parts of EU. There is too much vagueness concerning the forward, intraday timeframes, firmness etc… in the current draft.

*3. Should any of the timeframes (forward, day ahead, intraday) be addressed in more detail?*

We consider that all timeframes have to be described in some more detail, to ensure that there will be a common understanding and a consistent implementation in all parts of Europe.

For the forward timeframes of capacity allocation, we believe that the following important elements need to be addressed in the Guidelines:

- TSOs must sell transmission rights forward using the same timeframe as those used for trading electricity in the commodity markets. This process was agreed in the PCG and has been described in published EFET papers[1]
- A transmission right is an option on the spread between two markets and is (if no action is taken) a financial right automatically cashed out at day ahead stage on the power exchanges. The cash out occurs through a market coupling algorithm or at the explicit D-1 auction clearing price; the right remains an option until H-30 minutes, after which it turns into an obligation
- A transmission right is freely tradable, individually, as part of a block or indeed according to any particular profile that a buyer and a seller may agree.

For the intraday timeframe, the non discrimination between OTC and organised market, as expressed in Article 5.5 of the Guidelines, should be reaffirmed. A stipulation that no congestion fees are to be applied to transactions, when intraday capacities remain available, should be introduced. The continuance of certain essential TSO services available to market participants, should also be clearly expressed, such as freedom to rebalance positions cross-border or to flow some power cross-border (transit flows) where intraday capacities remain available. Also missing are a reference to continuous allocation on the basis of obligatory use and some explanations on the difference between the concepts of pooling liquidity, transparency on transactions, assuring reliability of intraday market prices or defining market monitoring principles. Having a clear definition and understanding of these concepts seems to be necessary if we want to progress when discussing the intraday Target Model.

*4. In general, is the definition of interim steps in the framework Guideline appropriate?*

The Guidelines should give a clear and detailed description of how and when capacity allocation and congestion management shall be implemented throughout Europe, with full implementation not later than 2015.

[1] Please see EFET papers "Electricity transmission capacity rights: Making firmness a reality", and Dual Purpose Transmission Rights: The pros and cons of physical and financial transmission capacity rights and a recommended EFET approach for a pan European model", November 2008, available on www.efet.org

The Guidelines would ideally set out what are the requirements and state that these are mandatory with immediate effect. Given the fact that the starting points in different regions may be very different, interim steps should not be laid down in the Guidelines. Instead, there should be a clear statement that any interim solutions need to take the target model into account and must not delay the implementation of the target model. In the meantime, Regulators must rely on their own coordination and TSO coordination at regional level, to ensure that intermediate steps do not bring with them any threat to existing market liquidity and stability, as explained in our introduction.

*5. Is the characterisation of force majeure sufficient? Should there be separate definitions for DC and AC interconnectors?*

A much clearer definition of *force majeure* must be set out in Article 5.11 to avoid divergences at national and regional level. We see no reasons for separate definitions of *force majeure* for DC and AC interconnectors.

The EFET view is that *force majeure* is the only reason for curtailment without compensation at full market value. We recognise that there is a risk that, until auction terms are harmonised across Europe (a role for ACER and ENTSO-E), the definition of *force majeure* will differ among various sets of auction rules.

There are certain key elements that every *force majeure* provision must include. *Force majeure* should be restricted to an actual event or circumstance which:

1. Has occurred (not one that is anticipated to happen or prevail in the future); and
2. Is objectively verifiable.

A *force majeure* event or circumstance must additionally:

1. Not be reasonably foreseeable by the claiming party
2. Be beyond the reasonable control of the claiming party
3. Be not reasonably avoidable by the claiming party, and
4. Impede the claiming party from performing its obligations.

A system emergency or “security event” declared by the TSO is not in and of itself *force majeure*, unless the specific event leading to the declaration of a system emergency is independently a *force majeure* event. TSOs retain discretion to declare a system emergency if needed, in order to maintain system reliability, even if a *force majeure* event has not occurred. For instance:

- The combination of planned maintenance outages and unseasonably hot weather in the summer could impact reliability, but would not constitute *force majeure*
- Curtailment owing to system availability difficulties or for other system “reliability reasons”, as perceived by the TSO, should not justify a claim of *force majeure*.

A TSO will declare a *force majeure* event when it determines it is able to do so under the provisions of the applicable auction rules. If an affected market participant agrees with the TSO's assessment, the *force majeure* event is effective. If that market participant disagrees with the TSO's assessment, the parties will work out a commercial settlement and/or the dispute resolution provisions of the auction rules may be triggered.

*6. Do you agree with the definition of firmness for explicit and implicitly allocated capacity as set out in the framework Guideline? How prescriptive should the framework Guideline be with regard to the firmness of capacity?*

The framework Guideline must define firmness of capacity in detail. EFET has a preference for physical firmness above financial firmness. In the case of physical firmness, a cross-border nomination must be honoured. The TSOs involved then solve any system imbalance on either side of the affected border by national or cross-border redispatch or even by countertrading. The result is that a physical commitment to firmness enables market participants to avoid re-nomination and also averts the complication of arranging financial compensation.

The Guidelines do capture some vital principles and issues, such as:

- If financial firmness is being used, curtailment of cross-border transactions may only be applied in case of *force majeure* or in emergency situations
- Holders of capacity in the form of PTRs or FTRs shall be compensated at the relevant market spread in an emergency situation and by reference to the initial payment (to the TSO, not in the secondary market) in the case of *force majeure*
- Allocated day ahead capacity must be physically firm even in the case of *force majeure* to ensure that anticipated market coupling outcomes will not be distorted (But see our comment at the end of the preceding paragraph.).

In particular, EFET considers that the following must be tightened within Articles 5.5 - 5.10 or repeated and adapted in Article 3 (dealing with the forward timeframe) for additional clarity:

- While already precluded by the Congestion Management Guidelines, TSOs must not favour internal over international transactions, and any action to curtail or countertrade must be transparently undertaken by the TSO, to show that the action was the most efficient one, based on market prices
- Congestion rents should, in priority order, be used for (1) guaranteeing the firmness of capacity rights; (2) investment in relieving binding constraints.

The compensation measure for curtailment in Article 5.9 mentions day ahead, intraday and balancing price spreads correctly as the reference prices during those timeframes.

However, the Article fails to describe how for time periods of days or weeks ahead of real time, where the future spread is the correct measure of remuneration, arrangements for TSOs to manage congestion shall only be possible through buy back of capacity in the marketplace or through the arrangement of a reverse auction.

For the allocation of longer maturity rights, EFET encourages the further development of auction offices handling as many borders as possible, based on a harmonised set of auction rules.

*7. Which costs and benefits do you see from introducing the proposed framework for Capacity Allocation and Congestion Management? Please provide qualitative and if applicable also quantitative evidence.*

There is a range of potential benefits that will come from improvements to capacity allocation and congestion management. In the short term, there will simply be more efficient use of the networks in a static sense – often termed "social welfare" gains from more efficient pricing in real time. In this respect, the largest benefit is expected to be achieved in making more capacity available for the market. Current approaches are partially based on arbitrary rules and are probably based on too pessimistic scenarios. Also the practice of shifting internal congestions to a national border is likely to be very often not optimal. At the same time, we admit that some benefits would anyway materialise, if Regulators would more rigidly ensure compliance of TSOs with existing rules.

In addition, liquidity should increase to the extent that the functioning of the wholesale market is improved. This will reduce transaction costs and permit more competitive markets by allowing a higher level of entry into generation and retail activities. In this context, it is worth noting that small price zones may well reduce liquidity and therefore decrease price certainty, when energy intensive consumers and generators consider new investments. Also, well-functioning retail markets could be hindered by smaller price zones.

More liquidity and competition will provide dynamic benefits by giving better investment incentives and encourage cost reduction and innovation. Implementing the Guidelines will facilitate robust cross-border competition, which should help consumer prices.

There are some potential trade-offs between short term efficiency of network operation and long term incentives. In this respect, our impression is that the consultation document takes a short-term perspective, based on its day ahead "allocation" focus. Perhaps more attention is needed to the long term incentives for network investments as part of the "congestion management" tools.

Costs and benefits are difficult to quantify at this stage. However, it is clear that the benefits of implementing the Guidelines will be significant. These benefits will not just come from simple improvements in dispatch efficiency, but also through:

- Higher liquidity leading to lower transaction costs,
- More effective competition driving cost reductions and innovation,
- The avoidance of unnecessary investments in, for example, peaking plant.

Implementing the Guidelines will also give greater scope to accommodate wind generated output and therefore enable CO2 savings. We believe that benefits will be higher in the case of large, liquid trading zones which will increase competition and encourage new market entry.

Although it is difficult to make quantitative assessments, the EU27 electricity consumption of around 3500 TWh corresponds to expenditure of over Euro 300bn per annum. So, even a small percentage reduction in costs arising from these improvements would amount to gains measured in billions of Euros per year. It is difficult to imagine that the costs associated with implementing the Guidelines will exceed such amounts.

### *Section 1.1: Capacity calculation*

Short term and long term capacity calculation should be defined. EFET has always insisted and still insists that the calculation, against which the allocation of longer maturity transmission rights is determined, should not be primarily based on "long term" physical availability estimates, rather on the commercial capacity of a TSO to issue those rights.

Definitions of and descriptions of the permissible means of calculating TRM or FRM are needed. Also the justification for application of reliability margins should be circumscribed. Reliability margins currently seem to be partially applied, to compensate for feared inaccuracies in hypotheses or scenarios. It seems that currently, when TSOs adopt more "optimistic" scenarios, in terms of the ability of the network to accommodate greater flows, they then apply higher reliability margins, which tends to cancel out the optimistic view. TSOs should instead strive to find a correct balance between optimistic and pessimistic scenarios. A reduction of the available volumes of transmission capacity (as a consequence of pessimistic scenarios / high reliability margins) results in welfare loss. The downside of too optimistic scenarios (or too low reliability margins) would be potentially a series of transmission capacity buyback programmes or increased need for curative redispatch. These two aspects (preservation of welfare and security) should be properly balanced by appropriate regulatory decisions, particularly the introduction of tailored incentives for TSOs.

*8. Is flow-based allocation, as set out in the framework Guideline, the appropriate target model? How should less meshed systems be accommodated?*

Methods, which better reflect the impact of the network on the interdependence of the transfer capacities on the different borders, are in theory superior. Methods, which use more arbitrary rules for allocation of transfer capacities over different borders, are inferior. The application of the former methods should result in higher welfare, because of increased transfer capacities and/or higher network security. Such benefits are likely to be higher in case of highly meshed networks than in case of less meshed networks. However, this should not preclude the application of the theoretically superior method in the case of less meshed networks.

At the same time, flow based allocation is more complex for market participants, compared to the ATC approach. Improper implementation might easily lead to worse results. Therefore, clear and substantial benefits have to be demonstrated before flow based allocation is introduced. As stated in the IA, there is so far no experience from flow based allocation in Europe.

EFET believes that at this stage the priority is to improve the co-ordination of allocating capacity on an ATC basis. Another priority is to increase the amount of firm capacity made available in the forward market, as a result of this improved coordination.
So, with respect to longer maturity transmission products, EFET considers that these should continue to be sold on an ATC basis, even if day ahead and intraday congestions are managed through flow-based allocation methods.

*9. Is it appropriate to use an ATC approach for DC connected systems, islands and less meshed areas?*

Less meshed systems should be treated in the same way as meshed areas, so that forward allocation remains as a bilateral ATC process, while any possible market coupling is introduced using a flow based methodology.

*10. Is it necessary to describe in more details how to deal with flow-based and ATC approach within one control area (e.g. if TSO has flow-based capacity calculation towards some neighbouring TSOs and ATC based to the others)?*

Yes, it is necessary to describe this in detail.
TSOs should always strive for maximisation of welfare. The existence of both flow-based and ATC-based methods used for day ahead allocation on different borders of the system of one TSO cannot be optimal (unless of course with very low influence factors[2]).  Therefore coexistence should only be contemplated, if at all, for an interim period.

[2] EFET rejects the use of flow based allocation for the forward timeframe earlier than D-1, as explained in our answer to question 8.

*11. Is it important to re-calculate available capacity intraday? If so, on what basis should intraday capacity be recalculated?*

Yes, it is important to recalculate available capacity intraday, to ensure that the market has access to maximum capacity and that the system is secure. The capacity should be recalculated based on changed status and forecasts of the transmission system itself, generation and consumption. Such forecasts will be more precise while approaching real time operation. Therefore, it is important that TSOs regularly recalculate capacities as far as practically possible. The increasing amounts of intermittent generation will make recalculation of intraday capacity more relevant. It is impossible for EFET to state how often recalculation needs to be done. It will depend on the specific situation. Even an hourly recalculation could be appropriate, and is feasible, with regular exchange of information between TSOs. If a recalculation leads to an additional 10 MW capacity being made available, this could already have a substantial positive impact on welfare.

*Other remarks on section 1.1 capacity calculation*

Paragraph 1.1.7 requires that TSOs describe and publish the methods and models taking into account the critical branches. However, the application of critical branches (not being interconnectors), while calculating cross-border capacity, *de facto* means that internal bottlenecks are shifted to the border. Such practice can only be allowed under certain conditions (see Article 1.7 of Congestion Management Guidelines). Therefore, the application of critical branches can only be allowed after proper justification of the need for such application. EFET underlines that the existence of critical branches within a zone does not necessarily have to lead to splitting the zone. The answer to question 13 provides the EFET view on the criteria to be applied for determining the delineation of zones.

***Section 1.2: Zone delineation***

EFET believes that ACER, in cooperation with the Regulators, will be the appropriate authority for review of delimitation of zones, given its importance for cross-border trading and the possibility for bidding zones crossing national borders.

But it is important to note that the debate about delineation of zones is complex and needs significant further debate and impact assessment.

*12. Is the target model of defining bidding zones on the basis of network topology appropriate to meet the objectives?*

EFET believes that bidding zones should be as large as possible and not necessarily limited by national borders. If structural congestions occur within a bidding zone, redispatch costs will increase and TSOs might need to propose preventive redispatch to manage the congestions efficiently. These costs will need to be met via the use of appropriate regulatory incentives.

Balancing mechanisms, preferentially with locational price signals, are appropriate for this congestion management and TSOs interventions on markets should be restricted as much as possible (such as countertrading). Balancing mechanism should usually be used after the market, unless the pre-solving of some constraints is possible through national or cross border redispatch or topology measures, with limited costs and allows more cross border market flows, in which case it should be used since it would guarantee an increase of the global social welfare.

It makes sense to define bidding zones on the basis of network topology and on the existence of structural congestions (although it is not necessary to split bidding zones in case of structural congestions) instead of simply following national borders. It should be possible that bidding zones cover multiple countries or combine parts of several countries. At the same time, EFET underlines that more redispatch does not necessarily mean less efficient dispatch overall. Minimisation of redispatch as such should therefore not be an overriding criterion. In the reply to question 13, EFET suggests other criteria that need to be used when defining bidding zones.

Furthermore it is important that bidding zones are stable, to ensure that counterparties are not subject to the risk that bidding zones change during the lifetime of a contract. Existing congestions, that appear to be structural, will not only disappear in case of transmission investments but might also disappear quickly in case of changes in the generation merit order (for example due to larger changes in fuel and $CO_2$ prices, in nuclear exit plans or in renewable subsidy schemes). This illustrates that it is important to avoid making unnecessary changes to the boundaries of bidding zones.

EFET does not believe that bidding zones should vary in different timeframes. There needs to be the same definition for forward, day ahead, and intraday markets. Obligations on market participants to balance and pay imbalance prices should also be set on the basis of these bidding zones. It should be noted, however, that the process of procurement of balancing energy by TSOs may introduce some locational elements within the bidding zones, reflecting the influence of balancing actions on network flows.

*13. What further criteria are important in determining the delineation of zones, beyond those elaborated in the IIA and FG?*

EFET believes that the draft framework Guidelines have a too narrow perspective when discussing the definition of bidding zones. The ultimate goal is a single European electricity market. A possible split of existing bidding zones will be difficult to understand for many consumers and will add complexity.

As mentioned before, EFET believes that bidding zones should be as large as possible and not necessarily limited by national borders. Structural and severe congestions could set the natural boundary between bidding zones.

A starting point for a proper delineation and sizing of bidding zones is welfare maximisation. However, such a welfare approach should not be limited to a static economic dispatch of generation and consumption. Also efficiency of transmission and of wholesale and retail trade and supply should be considered. Finally, dynamic aspects (such as investments and expansion of generation and transmission capacity) need to be considered. This leads to the following list of possible criteria:

1. Optimal generation and consumption dispatch:

- Larger zones will entail more congestions that need to be managed by redispatch (or countertrading) by TSOs. In case of structural and severe congestions that need to be managed by curative redispatch only, there is a risk that dispatch will not be optimal. EFET believes that existing bidding zones should be merged in case of absence of structural congestions

- An indication for non-structural congestions can be based on (a combination of) the following criteria (the numbers below are first estimates):
    - Day ahead price convergence for >90% of the time
    - Average congestion revenues <2 Euro/MWh
    - Interconnection ratio >5%

Smaller zones in theory bring the advantage that cross-border capacities can be calculated more precisely. However, in practice, even in larger zones, if net import/export volumes between zones are calculated with a detailed common network model, precision is superior. In that case, generation patterns of specific power plants are correctly represented at specific nodes (through Power Transfer Distribution Factors (PTDF) and Generation Shift Keys), when calculating available transmission capacity between zones. This choice combines the benefits of a nodal approach (by using a detailed network model) and of a zonal approach (by having one price in the zone and by having freedom of dispatch within the zone). In other words, the benefits of a nodal approach for the efficient management of the network can also be obtained when using a zonal market design, through the use of a common grid model.

2. Market liquidity:

- Larger zones will mean higher liquidity. This applies especially for forward products (e.g. year ahead contracts), that currently cover the largest share in traded markets. Liquid markets mean lower transaction costs, lower risks and lower likelihood that market power can be exercised

- Small bidding zones will add to investment uncertainties for generators and energy intensive consumers.

3. Proper incentives for TSOs to increase transmission capacity to avoid and solve congestions:

- A consequence of larger bidding zones is that congestions within the bidding zone will have to be managed through redispatch (or counter-trading) by the TSO. This has the consequence that the TSO primarily carries the cost for such congestion management. (Obviously the TSO must be able to cover such costs through its revenue from transmission tariffs. They It will lose the congestion revenues, which would have been available, if zones were split into smaller bidding areas.). So, a major advantage of larger bidding zones is that the TSO will incur an incentive to avoid or reduce congestions, which result in welfare gain. TSOs, which have invested in network expansion, will be rewarded for having few or no congestions

- Currently TSOs collect large amounts of congestion revenues from existing borders between bidding zones, whereas only very low redispatch costs are incurred to solve congestions on those borders. EFET has no access to detailed underlying data, but assumes that the ratio congestion costs / congestion revenues per border is very low. This is a strong indication that currently available transmission capacity values are set too low, that the market is not facilitated optimally and that TSOs should be incentivised to make more capacity available.

4. Well functioning retail markets:

- Smaller bidding zones in one country will make it impossible - without undesirable end-user price regulation - for retail suppliers to offer competitive country-wide prices. This will reduce the number of competing retail suppliers and will act as an entry barrier, resulting in higher supply costs for consumers.

Finally, we raise two criteria, often mentioned as important, which we feel are exaggerated:

- Locational price signals for generators and consumers:
    - It is sometimes said that smaller price zones have the advantage of providing locational signals through the market price to generators and consumers. The actual impact of such signals on the decision to build a new generation unit is modest, since only very few sites are usually available for new power plants. Other locational factors, such as the availability of cooling water for power plants, environmental constraints, or grid connection costs, are likely to play a more important role in the final decision.

- Transparency:
    - It is sometimes said that smaller bidding zones transparently demonstrate the value of congestions through the market prices in each zone. We believe that this is not a strong argument because:
        - The congestion revenues (the product of the price difference and the available capacity) are only a part of the socio-economic benefits of a relevant interconnection
        - In the case of congestion within bidding zones, TSOs could make more effort in providing information on its economic impact and the possible benefits of mitigating it, e.g. by network expansion.

EFET disputes the argument in two statements set out in the Initial Impact Assessment (IIA), sub-section 4.4.2:

- "*It is also possible to aggregate bidding areas into one price zone, as is done in Italy, which is divided into six bidding areas, but with uniform pricing on the demand side (i.e. the demand price is the average of the zonal prices weighed on the zonal consumptions).*"
  It is true that this solution is possible. Nevertheless, it is not in line with a basic free market principle, according to which consumers and producers should each face the consequences of a natural wholesale price in their bidding zone. Customer prices not reflecting a local wholesale price will not result in proper demand side incentives, and will mask the signals when for TSOs and distribution grid operators to develop smart grids, smart metering and other demand side management solutions

- "*Indeed, the relevance of a price signal in day ahead may be questioned if large amounts of redispatching costs are necessary to ensure system security and if these redispatching costs are socialised on all network users and not charged to those who are responsible for it.*"
  The basic principle is that the TSO is responsible for keeping a bidding zone together, and network users cannot be responsible for redispatch. TSOs should face incentives or obligations to make investments necessary to avoid a large amount very onerous incidence of redispatch, the costs of which must be socialised. In case investments will have not yet been undertaken, redispatch will continue to be needed, and should consequently be socialised as well.

Finally, we make the following suggestions for changes in a few sub-articles:

- Sub-article 1.2.3 stipulates that "… *in cases where … there is no significant internal congestion within or between control areas, one or several control areas may constitute one zone*". In this sentence "may" should be changed into "should preferably"

- Sub-article 1.2.4 stipulates: "*Several zones are possible in case of structural congestion within the control areas, which cannot be solved by methods of countertrade / redispatch or where the welfare gain is higher with smaller zones*". This should be changed into "Several zones are <u>only</u> possible in case of structural congestion where the welfare gain is higher with smaller zones"

- Sub-article 1.2.4 stipulates: "*In any case, the impact of redispatching/ countertrade costs on the welfare related to the delimitation of zones shall be taken into account.*" This sentence should be reconsidered, since redispatch/ countertrade costs as such are not detrimental to welfare. Redispatch/ countertrading only results in a welfare loss if it leads to a less efficient dispatch of power plants. We do not accept that redispatch/ countertrading would by definition result in less efficient dispatch than the creation of smaller zones / market splitting. Part of the reconsideration we advocate will require examination of the potentially positive impact on welfare of creating incentives for TSOs to solve/ avoid congestions and of averting jeopardy to the liquidity of forward markets

- Sub-article 1.2.5 deals with the issue of shifting internal congestions to the border. This paragraph is more weakly formulated than the existing Article 1.7 of the Congestion Management Guidelines). EFET recognises that in the case of new bidding zones, whose borders may not coincide with national or control area boundaries, it will be advisable to revisit the strict presumption against shifting congestion. We suggest the following principles could be applied, subject to review by DG Competition:
    - TSOs may not use their grid tariff income, nor their revenue from auctioning transmission rights, for preventive redispatch or countertrading, with a view simply to shifting binding congestion to the boundaries of a control area or of a Member State per se
    - However, TSOs may so use grid tariff income with a view to preserving the boundaries of a bidding zone, which has been pre-approved by ACER
    - Once a bidding zone has been so approved, TSOs must apply revenue from auctioning transmission rights for maximising the transmission capacity allocated to the market over the boundaries of that zone and for guaranteeing the financial firmness of previously sold transmission rights as well as the physical firmness associated with the day ahead auction, which guarantees the integrity of day-ahead prices

- Sub-article 1.2.5 of the Guidelines should also prevent the application of ramping restrictions on interconnectors (e.g. within the Nordic market and between the Nordic and continental European markets). Current ramping restrictions entail a shifting of internal network problems towards borders. Ramping could instead be solved by TSOs in the ancillary services market and Regulators should be guided to investigate this alternative.

- Sub-article 1.2.6 contains an obligation for TSOs to submit a yearly analysis to the Regulators. We consider that this analysis should be made public and should be transparently integrated into network expansion plans.

***Section 2: Forward markets***

*14. Are the preferred long-term capacity products as defined in the framework Guideline suitable and feasible for the forward market timeframe?*

As we indicated previously in our papers, EFET insists on the use of consistent and coherent terminology; "longer maturity transmission rights" is a more accurate term than "long term capacity products".

Financial Transmission Rights (FTRs) and Physical Transmission Rights (PTRs) are important for cross-border competition in the forward markets. As foreseen in the Conclusions of the PCG, FTRs or PTRs must be implemented in a consistent way between all bidding zones in all parts of Europe. The Guidelines must clearly state that all TSOs shall allocate FTRs or PTRs corresponding to the full available capacity.

The Contract for Differences (CfD) as used in the Nordic market does not fulfil a requirement to underpin cross-border competition in the forward market. CfDs are very different instruments, which do in fact not bear any link to the underlying physical transmission of capacity. The physical path from one price area to another is not incorporated into the design of a CfD. A CfD relies just on the difference between an area price and a "virtual" system price. CfDs are a type of financial instrument inappropriate for managing cross-border market exposure, primarily because TSOs do not issue them. Market participants themselves can generally not take on a price-spread risk between two markets, because they do not possess the ability to manage such a risk. They will still be missing any actual transmission product to provide a valid, natural hedge. Even trading companies, which might in principle be willing to take such risks, would normally only occasionally and to a limited extent be able to offer market spread hedges off the back of other commodity transactions.

A quick analysis shows that cross-border competition will be improved if transmission rights are used instead of CfDs. A generator would proceed in the following way to hedge a cross-border sale to a customer in another bidding zone in the two cases of a CfD and of a transmission right.

- <u>CfD</u>

  The generator would sell a CfD to a customer (as a fundamental buyer of CfDs) in its own bidding zone and buy a CfD from a competing generator (as fundamental seller of CfDs) in the other bidding zone.
- <u>FTR</u>

  The generator would buy a transmission right in an auction arranged by the TSOs or in the secondary market and would not have to buy any hedging instrument from its competitor. The TSO who has a naturally long position for the FTR should have no difficulties in selling these rights.

*15. Is there a need to describe in more detail the elaborated options for the organisation of the long-term capacity allocation and congestion management?*

Yes, the process whereby TSOs assess long run congestion and issue longer maturity transmission rights must be described in detail. Transmission rights should be allocated in a co-ordinated way, preferably by a single auctioning office. This requires consistency of processes and definitions and coordination of timings. It is therefore suitable for the guidelines and then the network codes to specify this in detail. Experience in the ERIs teaches us that it will remain hard to ensure that allocation of longer maturity rights is implemented in the same way around Europe. Similar implementation is an inherent aim of the target model developed by the PCG and can only be realised by creating clear, binding EU guidance on what are and are not options, when it comes to national or regional regulatory/ TSO/ power exchange discretion.

***Section 3: Day Ahead allocation***

*16. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the day ahead allocation?*

Yes, first of all the target model should be described in detail to ensure that it is implemented in the same way around Europe. It is important for the day ahead allocation phase to reflect the competitive nature of the provision of exchange and clearing services. Although most Member States only have a single day ahead exchange, this need not be the case in future. It is therefore important that any shared order book (SOB) functions, utilise open architecture software. These functions must not constitute a barrier to entry to new platforms, or the expansion of existing service providers. The IT specification should be part of the high level properties of the SOB (or market coupling) and the matching algorithm should therefore be accessible to any exchange platform that wishes to use it, provided that the appropriate technical and commercial conditions are met.

We also consider the principle of self dispatch of generation plants, embodied in the Directives, as being pre-eminent. Except for real time balancing and reserve markets operated by the TSOs, producers should not be subject to obligations to participate in any particular market when offering their capacities. The same goes for other market participants, concerning their trading activities. In addition, EFET expects day ahead markets only to relate to the purchase and sale of energy. Market participants should be expected to submit bids and offers in the wholesale market only as energy. Parameters relating to fixed and start-up costs, ramp rates, feed-in tariffs, etc. should not form any part of bidding in day ahead markets and it should be up to market participants how these are taken into account in their bidding behaviour.

### *Section 4: Intraday allocation*

The specificity of the intraday timeframe, in contrast to other timeframes, is the absence of a final market design model. Although additional detail and clarification in Guidelines and codes are therefore still needed, EFET recommends continuation of new cross border intraday projects. They can provide added value services, as a complement to existing intraday trading arrangements.

We do not understand the statements in Article 4.5: "*Intraday allocation and trade foreseen in the CACM network code(s) shall be coordinated by the TSOs with redispatching/ countertrade and with (cross-border) balancing markets, while being guided by the principle of overall efficiency…* ", and "... *efficient arbitrage with the day ahead and balancing time-frames is possible*". Intraday markets exist for the benefit of market participants and although they must be coordinated with balancing mechanisms, there should be no reservation of cross-border capacity for ancillary services, nor for balancing, nor for any other TSO to TSO contract.

As in other timeframes, TSOs should not participate in the intraday market, unless exceptionally justified and done in a transparent way (volumes, prices, duration, reasons for the intervention etc.). In this case, there must be sufficient visibility in real time, so that market participants can assess the impact of TSO's actions on markets.

Moreover, in the intraday timeframe, the TRM or FRM will have to take into account the decreasing uncertainty of TSOs assumptions (base case with exact values of injections, load forecast, transit flows, etc.) and they should therefore be releasing extra transmission capacity to the market close to real time.

*17. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the intraday allocation?*

Yes, the target model for intraday transactions must be described in more detail involving less scope for variations. The aim should be to ensure that it is implemented in the same way around Europe and that no liquidity is lost due to non harmonised models or operational constraints.

Non discrimination between implicit allocation and OTC trading should be guaranteed at any point in time and should be reaffirmed more clearly. Basic TSO services, such as affording market participants the possibility to rebalance positions cross-border or to flow power cross-border, should always remain possible where capacity remains available. This would be a direct application of the principle of free circulation of goods and services in the European Union.

We generally agree with the ideas set out in the IIA regarding intraday capacity allocation across borders, especially on the following topics:

- The "*general objective to provide market participants with an efficient way to balance their positions before real-time and trade energy as close to real time as possible, taking into account variable generation*" and "*to provide market participants with a wider range of options to balance their position in response to unanticipated changes in production*". This is also true for larger scale unexpected events, such as power plant outages and for all the changes that will occur close to real time on the hypothesis which had to be taken into account in the models at previous timeframes (such as weather forecast, load forecast, etc.)

- The objective "*to reduce overall system costs and provide more efficient flows*", this goes together with the general objective of "*promoting fair and efficient competition and cross-border trade*" at the intraday stage. EFET considers that this should ensure that the generation dispatch is correctly optimised by the market and that this should allow cross-border competition for "non-standard products" such as generation profiles and for the start of a generation plant. "Non standard market needs" are an important feature of the intraday markets in regions with a lot of thermal generation and it is important that the intraday market design does not only take into account standard products but all market needs

- The efficient articulation which needs to be implemented with balancing mechanisms in terms of operations (balancing starting after the intraday market) but also in terms of harmonisation and general design in order to provide correct incentives to the market and to allow secure system operations. The first incentive should of course be, as rightly pointed out "*for market parties to be balanced in real time in their balancing zone*"

- The importance of **time** at the intraday stage. The allocation mechanism must provide sufficient flexibility to create real intraday cross-border competition at the moment sellers and buyers make their decisions. It is essential in an internal market that these decisions at any moment may include cross border choices

- The interest to pool liquidity across the different hubs and through the various platforms; we also consider that this should be made without hindering competition between these various platforms. Therefore no exclusivity should be granted to a specific platform and the SOB and CMM should allow power exchanges and OTC markets to compete with no discrimination

- The fact that there should be no capacity reservation for balancing mechanism (tertiary reserve) or ancillary services (primary and secondary reserves) or even for TSO to TSO emergency contracts

- The importance to design an intraday market as close as possible to real time. We consider that trading should be allowed until the last hour before real time (H-1)

- The importance to stimulate and develop intraday markets. We consider that there is a growing maturity on intraday markets and that the intraday market liquidity will be built through the stimulation of non-exclusive initiatives

- The importance of having coherent intraday market design throughout Europe so that no artificial splitting of liquidity is done through potential operational constraints or lack of cross-border harmonisation (such as if fixed gate closures were proposed at regional level to perform implicit auctions)

- The fact that no cross-border congestion would occur when considering continuous obligatory use allocation process (allocation and use of the cross-border capacity until the last trade is matched) and that therefore the intraday capacities should be free in such a market design.

When considering the opening of the intraday market and transmission capacity release in the intraday timeframe, it is important that TSOs provide full, transparent information to the market. Bids and offers reflect market players' economic interests according to certain market conditions. It cannot be considered that an automatic matching can generate a congestion rent only on the basis of imperfect market transparency (no information on the capacity release for example). If some capacity remains available after the automatic matching, the capacity should be free, otherwise the price spread between the last trades that were matched can be considered as the clearing price.

In order to ensure non discrimination between OTC trading and implicit trading, a price signal should be used to reflect the OTC request for capacities at the opening of the intraday market or in the case of capacity release. We also point out that some national or regional market designs are still preventing intraday to trading from developing (such as the A to B to C rule in the Netherlands) and that intraday capacities are not yet available on some interconnections such as on the Italian interconnections.

On the proposed solutions, EFET has concluded that there are no good reasons for keeping implicit auctions at fixed gate times as a complementary model in any regional markets. There is a real risk to split liquidity and to lose some bids and offers, due to non synchronised timings or mechanisms, if some isolated implicit auctions continue to be organised for reasons other than an initial capacity release programme. If a European intraday market is the objective, there should be the same allocation method around Europe. We reject the notion that it would be acceptable to preserve regional exceptions, as long as they involve “adequate gate closures”: the unique model should be continuous trading with obligatory use.

We stress that an efficient intraday market design should be “customer oriented” and not “technology oriented” and should therefore not be defined or constrained by the existing continuous intraday trading initiatives and should always adapt to market needs, if a good functioning of intraday markets is the objective.

Moreover it is important that the respective roles of TSOs and service providers (platforms) should remain clear and that competition remains possible between various service providers. It is therefore very important that no exclusivity is granted to service providers. If de facto exclusivity cannot be avoided in the near term, regulatory controls may need to be put in place. TSOs, Regulators and market players should also always be able to ask for some improvements.

EFET has proposed a market-based roadmap, to allow the competitive development of intraday trading solutions and to enable an efficient stimulation of intraday market liquidity.

*18. Does the intraday target model provide sufficient trading flexibility close to real time to accommodate intermittent generation?*

The target model, as presently described, is not detailed enough to ensure that sufficient flexibility is guaranteed. Flexibility is not only needed for intermittent generation: flexibility is needed before real time in order to cope with changing market conditions during the intraday timeframe and in order to ensure that the cross-border competition is also effective within day.

Cross-border flexibility and competition for OTC and for “non standard” products and market needs should also be enabled, as it is a major contributor to the intraday flexibility, especially in regions with an important thermal generation mix. Full intraday flexibility is also essential for the security of power systems: the target model should allow for efficient intraday trade for all market needs.

The flexibility which is currently provided by TSOs to allow market participants to rebalance market positions through cross-border flows should not be lost nor limited by transaction fees, technical constraints or any other artificial barrier.

*11 November 2010*