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ACER consultation
The influence of existing bidding zones on electricity markets

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EFET Response – 30 September 2013

Key recommendations on behalf of wholesale power market participants for the conduct of any review of bidding zone boundaries

1. Overriding objective of completion of the single market

In conducting any review of bidding zones, we suggest that both ENTSO-E and ACER must, above all, take account of the overriding objective of the Third IEM Package: the realisation of one competitive and efficient market for electricity across the European Union. Transmission system operators (TSOs) have special responsibilities in this respect and they are obliged to cooperate, via ENTSO-E, "to promote the completion and functioning of the internal market in electricity and cross-border trade".

In attempting to fulfil this objective, ENTSO-E and ACER should take account of the historical development of the electricity sector in the EU and the starting position of the liberalised market as it has evolved to date. Since electricity systems have typically been developed at a national level, the sector is characterised by the existence of rather large companies, especially when judged by the degree of concentration at national or regional levels.[1] This is the case for generation, system operation and retail supply. From the European integration and competition perspective, one essential contribution of bidding zone configuration can be to help widen market areas and thereby help approximate market prices across the entire geography of the continent. This approach will yield the benefit of creating, to the largest extent possible, a true pan-European market where companies of any size, type and footprint can compete on an equal basis.

2. The impediment of (potential) wholesale market illiquidity

There was, until recently, little or no tradition for cooperation between system operators across Europe in terms of common market design, similarity of sector structure and norms of operational management.[2] There has been only a very limited trend towards the establishment of regional system operators, as seen in the USA. Nonetheless consumers have, since the end of the last century, reaped the benefits of market opening as traders active at the wholesale level learned rapidly to price wholesale power across national borders. Supply contracts at the retail level have remained typically

[1] Concentration is much less taken at a pan-European level, but the wholesale market is still divided geographically across the continent to a varying extent.
[2] Exceptions have certainly occurred, but mostly on a bilateral or trilateral basis between directly neighbouring TSOs or TSOs within one country.

based on a fixed electricity price over a particular period of time in spite of market opening, mainly owing to infrequent meter reading and to consumer preferences.

These historical factors have led to wholesale suppliers and traders carrying price, basis and volume risk since the onset of liberalisation. Such market participants can only bear such risks within their own portfolios if they are able to resort to hedging and offsetting transactions at any time. It follows that effective competition for the benefit of consumers requires liquid wholesale markets (by product and geography) in all timeframes. Especially important in maximising liquidity are forward contracts for the sale of electricity, accompanied by transmission rights for cross-border hedging purposes. Forward adjustments are axiomatic to enable supply businesses adequately to manage their production and purchase related risks, and efficiently to respond to an increase or decrease over time in their portfolio of customers.

This also means that although day-ahead markets are of course essential in providing a reliable reference price for the efficient cross border dispatch of assets at the day-ahead stage, they are only one element of overall wholesale market design. As such, well developed and liquid day-ahead markets can be considered as the nucleus on which forward and intraday markets can rely. But all of them are essential for the maintenance of intra- and cross-zonal competition.

Indeed, competition can be restricted by difficulties in accessing liquid forward markets across borders or by difficulties in accessing liquid intraday markets. The latter have become essential to balancing individual positions before real time and managing volume and price risks, especially since the expansion of renewable sources of generation.

We thus insist that account of these components of competitive markets should be central to any consideration of changing the configuration of bidding zones[3].
All existing geographic power **markets rely on a reasonable level of liquidity, depth and standardisation of transactions[4] to function efficiently.** The risk of illiquid bidding zones should be avoided as far as possible.

3. The benefits of larger zones and measures to facilitate them

Relatively large bidding zones including a sufficient range of buyers and sellers allow liquidity, market depth and standardised transactions to develop properly. These buyers and sellers should all be able to interact in liquid markets, in the same bidding zone for all timeframes: forward, day-ahead, intraday and balancing markets.

In some circumstances, a relatively high level of re-dispatch by system operators may be needed in order to guarantee the existence of a well-functioning bidding zone, with sufficient liquidity in all timeframes. In that case, these costs should not be considered as a social welfare cost, since they are essential for the proper functioning of wholesale markets in that bidding zone and for the existence and development of competition. This is a more effective and cheaper way to deal with incidences of localised market power rather than having to overlay measures to combat market power on the entire sector structure, which would be the case with smaller zones.

As such, **the management of network constraints, within which re-dispatch is one component, can be considered as an essential TSO function** for the maintenance of the integrity of the overall market framework.

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[3] It is worth noting that the existence of large liquid price zones is also needed for the nodal model to work and this needs to be bought about by availability of firm transmission rights between nodes.

[44] An important component of standardization is the resorting by market participants to the EFET Standard Master Agreement. It allows multiple transactions to be arranged quickly and flexibly under the umbrella of pre-arranged terms. Annexes specify the delivery hub, price and other variable conditions.

An integral part of this zonal approach must of course be to ensure that TSOs further develop coordinated network management tools and to increase their efficiency and reduce their costs.

We propose ACER should conduct a proper comparative assessment of forward and intraday liquidity prevailing in various geographic wholesale power markets globally. In this context we would note that the German forward market is probably the most liquid across the world (with a churn reported at of 8 to 9 times consumption volume). By contrast, for example among the US markets, the PJM-West region only has a churn rate of 2 to 3 times and other areas of PJM do not really have well-functioning forward markets at all.

Lastly, when it comes to the overall process of bidding zone revision, and especially envisaged stage 4 of the early implementation process, it is our view that TSOs are not capable of assessing the overall market efficiency and would also be put in a position of conflict of interest if they were to assess both their own needs and market needs. We would therefore recommend to take into account this healthy separation of roles and responsibilities and to ensure that market efficiency is evaluated by regulators and by market participants through a well organised and non-discriminatory market consultation process. Such consultation should not only involve local market participants but also all market participants active in surrounding markets.

We would also request that the forthcoming CACM Network Code reflect this separation of roles and responsibilities, as well as a requirement to involve all concerned market participants.

4. Summary

In summary, EFET would like to highlight:

- The need not to underestimate the welfare gains of liquid markets,
- The fact that small zones mean lower liquidity and therefore welfare loss,
- The importance of forward market in the discussion on bidding zones,
- The fact that retail markets suffer if liquidity of wholesale markets reduces,
- The reality that redispatch costs are not a welfare loss. Only if redispatch is inefficient, some welfare loss occurs,
- The priority that must be given to improving (cross-border) redispatch arrangements and cross-capacity calculation processes.
- The fact that loop flows are not a welfare loss.
- The length of the process of changing bidding zone delineation, which takes many years for decision making and for implementation. In the meantime, the grid and the market changes and the assumptions that were used when reviewing the zones might prove to be wrong. Therefore, one should be extremely reticent before making any changes.

1) ***How appropriate do you consider the measure of redefining zones compared to other measures, such as, continued or possibly increased application of redispatching actions or increased investment in transmission infrastructure to deal with congestion management and/or loop flows related issues? What is the trade-off between these choices and how should the costs attached to each (e.g. redispatching costs) be distributed and recovered?***

Before talking about loop flows and on how to best manage them, it should be clarified that physical loop flows and transit flows are an integral part of any zonal model, i.e. depending on the bidding configuration, the same physical loop flows and transit flows could either become all “loop flows”, all “transit flows” or all “internal flows”. As such, loop flows and transit flows cannot be considered as “good” or “bad” but just need to be managed, and the question is how TSOs coordinate in order to manage them.

Another clarification needs to be made on “unplanned flows”, which is the consequence of insufficient coordination between TSOs, and between TSOs and DSOs (no common grid model and no coordinated capacity calculation or insufficient exchange of information). These flows should not be “unexpected” if there was sufficient cooperation. In the case “unexpected flows” resulting from large renewable energy in-feeds, we believe that TSOs and DSOs already have accurate forecasts of in-feed from renewables and should be able to share this information with all neighbouring TSOs so that the exact impacts and flows are known. Also changing the definition of bidding zones is not necessarily the only solution and we would rather recommend using solutions which would not impact the market in such a radical manner, but rather solutions improving TSOs’ operational cooperation and exchange of information.

We also believe that loop flows should also be looked at from a wider market design perspective since they are part of zonal models and since completing the harmonisation of electricity markets in all timeframes towards the common target model should be the key priority of ENTSO-E and ACER in that respect.

<u>Infrastructure investment</u>

Expanding transmission capacity is the most common way to solve/manage structural congestions in terms of medium/long term solution, and an essential component of the different tools to achieve an integrated European electricity market. Increased transmission capacity may admittedly constitute a means to reduce market power.

However, network infrastructure development is often a very costly and long process (7 to 10 years or more). In some cases, increasing transmission capacity may prove impossible because of geographical, social, or cost constraints.

<u>Redispatch, including cross-border redispatch and other network constraint management tools</u>

When physical flows are expected to change, due to evolutions in network infrastructures or even in generation and load, all types of network constraints management tools should be considered as very useful congestion management method in the meantime and redispatch costs in those circumstances (and even more for minor congestions) should not be considered as a welfare loss per se, but should rather be assessed in the overall network dynamic and market context.

Also, redispatch is much too often considered as the unique congestion management method, whereas efficient network constraints management tools should also include topology measures (at almost no costs when available), coordinated operations on phase shifters (at almost no costs when available) and should be extended across border by developing multi

TSOs coordination operational centres such as Coreso, associated with cross-border cost sharing agreements.

We believe that a lot of progress and economies can be achieved in terms of efficient management of congestions and efficient use of existing network infrastructures by further the developing such initiatives.

We also believe that these initiatives will also bring some additional benefits in terms of security of supply and TSOs capacity to anticipate, prevent and manage network issues.

In this context, the costs of redispatch and of alternative coordinated measures should remain quite low compared to less efficient markets which would be based on smaller bidding zones (with less competition, increased market spreads and a decrease of the quality of order books).

Also, as already pointed out, the need for re-dispatch can also be lowered by improving the harmonisation of market design between bidding zones, in the wider context of a transition towards common target models.

The Inter-TSO Compensation Mechanism is meant to take into account the financial compensation related to the transit element of multi-TSO management of network infrastructure across Europe, including associated network losses.

When it comes to specific regional difficulties only arising from loop flows, we think they should be managed by regional bilateral or multilateral cost sharing agreements, associated with regional cross-border operational agreements.

Counter-productive effect of ill-considered bidding zone re-delineation

Redefining bidding zones will generate significant transition costs for TSOs and market participants, and will affect market efficiency in general. It would also send very negative signals in terms of regulatory risks, which are likely to freeze many investment decisions, with direct impacts on existing assets and portfolios. It should therefore be considered with extreme caution.

Also, in case of smaller bidding zones, the costs / welfare losses caused by the reduction of market liquidity in all timeframes and the associated decrease in competition in both the wholesale and retail markets should not be underestimated or neglected. In our view, Section 2.3 of the Consultation Document seems to ignore the negative impacts on the forward markets and on retail markets.

We reiterate the central need for deep and liquid forward markets over a range of base load and peak load products, with a forward tenor up three years, accompanied by hourly cross-border transmission rights between all bidding zones, issued months and years ahead. These measures are essential for the maintenance of competition and for the reduction of transaction costs for market participants and ultimately for consumers.

Further, we would like to highlight the uncertainty linked to a review and re-delineation of bidding zones under the current market design evolutions. Currently, TSOs are preparing improved methods for calculation of cross-border capacities (using a common grid model) for the allocation of cross-border capacities, including through flow-based market coupling and are also developing coordinated cross-border redispatch. This general market design evolution was supported by EFET over the past years at AHAG and AESAG meetings. However, the actual benefits of such improvements are yet unknown. The results of this fundamental market design change will likely show a new picture of the situation of the European electricity transport network. Therefore it is extremely difficult to measure and assess the efficiency of any bidding zone re-delineation in this context.

At any rate, any bidding zone review should be done with extreme care, on rare occasions, and taking into account all structural underlying elements and consequences (costs and benefits) as well as expected infrastructure and market design developments.

2) ***Do you perceive the existing bidding zone configuration to be efficient with respect to overall market efficiency (efficient dispatch of generation and load, liquidity, market power, redispatching costs, etc.) or do you consider that the bidding zone configuration can be improved? Which advantages or disadvantages do you see in having bidding zones of similar size or different size?***

In general, it can be noted that the costs of re-dispatch or of other network constraint management methods are comparatively small compared with the possible welfare gains by creating larger zones, due to increased liquidity and competition[5]. We also believe that network expansion will remain one of the most effective long term solutions for decreasing or removing structural network congestions.

Also, it is not obvious, nor reasonable to assume that all bidding zones should be of similar size. The existence of structural bottlenecks, the differences in generation mixes and market structure may result in very different bidding zone sizes and creating artificial or unnecessary bidding zones can only damage competition and market liquidity.

Overall, our experience is that some of the existing bidding zones are probably too small to support liquid wholesale market in all timeframes and a competitive retail markets. The same goes for market power which can only be decreased by enlarging bidding zones.

Likewise, reducing the size of existing bidding zones can be only economically justified in case of absolute necessity or if there is permanent congestion with no network expansion possible or justified under the socio economic cost benefit analysis, which could relieve this congestion in the foreseeable future.

It can also be noted that the current borders of most bidding zones do not go beyond the borders of the Member States. The complexity of creating bidding zones covering different jurisdictions or with very different market design (especially with different balancing mechanisms) should not be underestimated and would probably counter the potential benefits of this change. We would therefore advocate for a case by case analysis and also for a comparison of alternative proposals. In this context the perimeter of any bidding zones review should not be limited to the perimeter of positive impacts, but should also take into account potential side effects or impacts on surrounding markets.

[5] It should also be noted that these methods are only used when the reality of the physical constraints appears and are not based on a theoretical modelling applied in day-ahead which would systematically limit transactions. The social welfare loss associated with these systematically forbidden transactions is rarely taken into account in social welfare modelling studies, which consider that the outcome of the model in day-ahead perfectly reflects the reality of physical flows. This is not true and will increasingly become inaccurate with the development of RES injections and the development of intraday and balancing coupling mechanisms.

3) ***Do you deem that the current bidding zones configuration allows for an optimal use of existing transmission infrastructure or do you think that existing transmission infrastructure could be used more efficiently and how? Additionally, do you think that the configuration of bidding zones influences the effectiveness of flow-based capacity calculation and allocation?***

Our view is that the question of zone size is largely irrelevant to the question of whether transmission infrastructure is being used optimally or not. The main reason for non-optimal use of infrastructure is largely linked to insufficient development of operational cooperation and cost sharing agreements between TSOs.

In this context, Section 2.2 which suggests that "large bidding zones induce higher uncertainty in capacity calculation, which may result in higher reliability margins and reduction of cross-zonal capacity given to the market" is strongly biased. This is in our view a simplistic statement since TSOs already have a lot of "nodal" information irrespective of the size and structure of the market model and hence of market bidding zones. TSOs should already know today with a good level of precision the expected generation pattern from renewables based on weather forecasts and from conventional generation (as they know the availability and have estimate of the variable costs of each plant). In any case, the variability of RES injection would also cause uncertainty on small bidding zones. In reality, TSOs also have quite accurate load forecasts on a nodal basis. In conclusion TSOs should be in a good position to forecast actual flows in the network, irrespective of the size of the bidding zones.

Therefore, the optimal use of the transmission infrastructure will also be guaranteed by a transparent common grid model for capacity calculation and allocation that reflects all borders and intra-zone constraints.

Once the CACM code is in place TSOs will be able to collect further indicative information from generators in order to improve their estimations and there is already a large amount of data being published and easily available with REMIT and Transparency Regulation. These positive evolutions should be assessed before considering making significant changes to bidding zone delineation.

4) ***How are you impacted by the current structure of bidding zones, especially in terms of potential discrimination (e.g. between internal and cross-zonal exchanges, among different categories of market participants, among market participants in different member states, etc.)? In particular, does the bidding zones configuration limit cross-border capacity to be offered for allocation? Does this have an impact on you?***

The main reason for discrimination is the different levels of firmness with respect to access to the transmission network on a cross-border basis, compared with the national regime, which is infinite.

In this context, it is obvious that a copper plate situation whereby a market participant could access all potential customers throughout the EU on the same basis is only a purely theoretical model and would not be the most cost effective model in terms of network investments. The existence of different bidding zones is therefore a necessity. However this can only be a non-discriminatory arrangement where sufficient firm capacity is made available by TSOs between all bidding zones for all timeframes and the nature of transmission rights between zones is as close as possible to the "infinite firmness" of internal transmission capacity within each of the bidding zones.

This should be organised through an incentive on TSOs to make available the maximum amount of firm capacity between bidding zones and for the costs associated to this firmness guarantee to be covered by congestion incomes, as this is already the case.

The Swedish case could be considered as a good counter–example which led to a non-optimal solution. Indeed, SvK was accused of "shifting internal bottlenecks to the border", thus discriminating between cross-zonal and internal exchanges. In effect the rights offered between Sweden and Denmark available cross-border capacity was reduced before it was offered, as an instrument to solve internal congestions within Sweden. So there was too much difference of firmness between cross-border rights and national rights within Sweden.

However in response to these allegations, Sweden decided to split its internal market into four bidding zones in November 2011. An alternative, and better, solution would have been a requirement on TSOs to guarantee the firmness of long term rights with congestion incomes and to maintain the obligation on TSOs to guarantee internal congestions by solving the internal constraints though redispatch measures in the same way or by other network management measures such as topology measures or the implementation of phase shifters. Creating smaller bidding zones has directly impacted market liquidity in all timeframes and created other discriminatory effects by isolating the various bidding zones from each other and from the international market.

5) ***Would a reconfiguration of bidding zones in the presence of EU-wide market coupling significantly influence the liquidity within the day-ahead and intraday market and in which way? What would be the impact on forward market liquidity and what are the available options to ensure or achieve liquidity in the forward market?***

Liquidity is defined as a level of trading allowing buying and selling with minimum price disturbance at any time. It is a market ability to ensure market participants the "fair" price" in any situation (not only in the presence of congestions but also inside a bidding zone).

To that extent, we do not agree that the use of implicit allocation mechanisms would in any measure compensate the loss of liquidity associated with the re-delineation of smaller bidding zones.

First of all cross zonal capacity will always remain less firm and more limited than the internal "infinitely firm" and "infinitely available" transmission capacity. This is inherent to any zonal market model.

As a consequence, even if interconnectors are fully and efficiently utilised through implicit mechanisms (not for the forward timeframe in any case), a market split will occur when the interconnection capacity is congested. In these situations, generation and demand can only participate in their local bidding zone market. Market participants' ability to rely on the market is directly impaired because of this, since they have to expect a limited liquidity at certain times. Market participants with assets in these a bidding zone (generation and consumption units) will then face a market restriction, with a reduced number of counterparties and of bids and offers, and with a direct increase of local actors' market power.

Liquidity of forward markets would also be directly impacted by this likelihood of congestions and the same goes of course for intraday markets.

We already mentioned that the liquidity of forward markets, and/or the access to liquid forward cross-bidding zones hedging instruments towards more liquid bidding zones or easy access to local flexible products are a necessary condition for competition both in the wholesale and the retail market. Without liquid wholesale markets there can be no independent market entry and the prospect of real competition is severely constrained.

Most consumers and generators are unable or unwilling to have total exposure to day-ahead prices, so competition requires a high degree of liquidity of forward markets as a price discovery and hedging tool. This also allows companies to gain and lose market share and trade out of these positions. This is also why market monitoring by individual regulators tends to focus on this point.[6] An effective market requires a sufficient number of active market participants on both buying and selling side as well as some financial players providing additional liquidity or liquid hedging products towards other liquid bidding zones.

Prices in forward markets are important for market participants to make efficient operation planning decisions (like maintenance planning, fuel contract decisions, etc). Illiquid forward markets would result in inefficient prices and therefore inefficient operational planning decisions and as a consequence would result in welfare losses.

Price zones therefore need to be large enough to support the necessary critical mass of market participants and allow them to develop their activities.

The liquidity of forward markets will be particularly negatively affected by the introduction of smaller zones since the liquidity of the initial forward market would be split into the various new bidding zones. If one zone is split in two zones, the number of forward products would simply double while the number of market participants would likely decrease since all participants may not have an interest in all of the new bidding zones. This means that the liquidity of the forward market would be split over twice as many products and fewer market participants. Also the liquidity of cross-zonal hedging instruments is likely to be insufficient, especially for the most isolated bidding zones, thus further decreasing competition and efficiency of hedging. This would obviously have a negative impact on market liquidity and. retail markets would equally be negatively affected.

6) Are there sufficient possibilities to hedge electricity prices in the long term in the bidding zones you are active in? If not, what changes would be needed to ensure sufficient hedging opportunities? Are the transaction costs related to hedging significant or too high and how could they be reduced?

Even with the current zone configuration, there are only limited areas in the EU market where there are sufficient possibilities for market participants to hedge electricity prices.

- The German-Austrian market is the most liquid with a churn rate of roughly 8-9 x volume and a forward curve that goes out to around three years. Both base load and peak load products are available. This is generally sufficient for most hedging market needs.

- Other well-developed markets such as the Netherlands or Great Britain have a reasonable degree of liquidity with a churn of 3-4 x volume and a forward curve of two years. However there is not always sufficient opportunity to hedge forward peak load demand and there have been some regulatory efforts devoted to promoting this, culminating in the proposal for some mandatory market-making in GB. Participants in the Dutch market are nevertheless able to use the German market as a partial hedge.

- The Nordic market is only liquid for the overall system price and there are often no hedging products towards or from individual bidding zones in which generation assets and final costumers are located. Contracts for difference (CfDs) have a limited availability and induce additional transaction costs since they are not offered by TSOs. Also the available volume is not offered simultaneously through auctions such as PTRs or FTRs. They also

[6] See for example Ofgem's liquidity initiative.

very lack the reference to hourly granularity and do not allow to hedge peak and off-peak risks separately. This means that entering those markets may not be easy for all bidding zones and would mean carrying a basis risk which limits competition.

- On the Spanish market the churn rate is slightly above 1x, which provides some (but limited) hedging opportunities. The forward markets quote only products indexed to the Spanish price. There are no similar hedging opportunities in Portugal, where suppliers partially hedge using the products linked to the Spanish price and accepting the basis risk. REE auctions FTRs twice a year, but the amount is just 400 MW and the product is not traded in secondary markets[7].

- Other markets struggle to get a forward market going out more than a year or so and the hedging possibilities are limited. There are a range of reasons why this is the case depending on market structure, regulatory barriers or other interventions, end-user price regulation, etc.

7) ***Do you think that the current bidding zones configuration provides adequate price signals for investment in transmission and generation/consumption? Can you provide any concrete example or experience where price signals were/are inappropriate/appropriate for investment?***

It is a very disputable topic to consider that congestion income provides an incentive to remove congestions. On the contrary, it could be considered that congestion income provides a revenue stream that will not incentivise TSOs to relieve the cross-border congestion, whereas TSOs are incentivised to remove internal congestions in the most efficient way since the costs of managing these congestions is clearly identified as a cost.

Also when looking at the constraints to investments in network infrastructures, it strikes us that the financing component is never the most constraining factor (TSOs having usually very good credit ratings due to their regulated and very low risk activity). On the contrary local oppositions and potential technical and administrative constraints seem to be the overwhelming factor explaining delays and difficulties in network investments.

The consequence of this is that the traditional economic and market theory around price signals is not at all well adapted to describing the dynamics around network investments.

It is also worth noting that similar factors also tend to apply for significant generation investments (over 100 MW), for which connection to the network and many other factors often play a major role in investment decisions.

In any case TSOs have the statutory obligation to (i) use the existing the transmission infrastructure to the maximum extent, and (ii) expand the transmission grid in order to reach at least a threshold of 10% interconnection capacity. The choice of size of market bidding zones should not be of any importance for stimulating or incentivising TSOs to act properly. Instead, bidding zones should not be defined in a badly correlated manner compared to structural network congestions and more transparency would be needed on how TSOs calculate ATC values, on redispatch costs, etc. This increased transparency would arguably help regulators incentivise TSOs in the most efficient way concerning investment studies and investment decisions.

[7] For additional details on Iberia, please refer to the annex.

As already pointed out, neither congestion rents nor redispatch costs can be considered alone as a good economic signal for investments in transmission infrastructure. At the best they are a rough indication that one should consider an investment. Firstly, the welfare gain of trading over an interconnector is not just the congestion rents but also the increased consumer and producer surpluses which will not be captured by TSOs. Secondly, the benefits of increasing interconnection capacity is defined by the increase of this total welfare gain and not by the welfare gain obtained by the current interconnector alone, which would in fact decrease.

As far as investment signals for generation/consumption are concerned, the supposed benefits of smaller zones (and therefore “more correct” prices) on such investment signals are largely overestimated. On the contrary, the risk of changes in bidding zone delineation would potentially be a strong negative signal. For most investments, forward prices are an essential indicator, and the loss of liquidity that comes from smaller zones will erode the individual price signal. In addition, generation investment decisions are taken on the basis of a combination of factors including forward prices, supply-demand projections, strategic considerations, negotiations with equipment suppliers and possible regulatory incentives (locational or otherwise).

8) ***Is market power an important issue in the bidding zones you are active in? If so, how is it reflected and what are the consequences? What would need to be done to mitigate the market power in these zones? Which indicator would you suggest to measure market power taking into account that markets are interconnected?***

It is obvious to us that market power would tend to increase with smaller bidding zones and to decrease with larger bidding zones. Regulators are used to calculating market power indicators and we do not consider that any new indicator needs to be invented in that respect (such as the definition of market power used in the consultation document).

It is very disputable to think that smaller bidding zones will have beneficial effects in terms of volumes of transmission capacity being offered... if the argument which is used by TSOs to explain decreasing cross-zonal capacity relates to the growing uncertainty of RES injection, the reduction of the size of bidding zones are very unlikely to remove that uncertainty.

Also it should be noticed that the integration of European markets will have beneficial effects in terms of decreasing market power for all timeframes. These beneficial effects could easily be impaired by inadequate changes in bidding zones configurations, which is why we remain cautious on the objectivity of TSOs and regulators’ analysis in this field and which. A thorough market consultation is essential on these matters.

9) ***As the reporting process (Activity 1 and Activity 2) will be followed by a review of bidding zones (Activity 4), stakeholders are also invited to provide some expectations about this process. Specifically, which parameters and assumptions should ENTSO-E consider in the review of bidding zones when defining scenarios (e.g. generation pattern, electricity prices) or alternative bidding zone configurations? Are there other aspects not explicitly considered in the draft CACM network code that should be taken into account and if so how to quantify their influence in terms of costs and benefits?***

As previously stated, we do not consider that ENTSOE or groups of TSOs have the necessary knowledge and objectivity to conduct a complete “market efficiency” analysis.

This is also due to the inevitable conflict of interest between TSOs' duties (mainly around security of supply, limiting network or system constraints, and with a natural incentive to decrease their own risks) and the interest of a well functioning market (sufficient firmness and volumes of cross bidding zones hedging instruments being offered at all timeframes, opening markets as close as possible to real time with sufficient flexibility, allowing transactions across several borders).

We would therefore request a two level process (TSOs, regulators) to be kept also during activity 4 and for market participants to be closely involved to these studies, especially concerning the market efficiency analysis.

Also EFET deeply regrets that ENTSO-E did not take the opportunity to define the details of the cost-benefit analysis (including the method to evaluate the technical and economic consequences for different bidding zones) in the CACM network in more detail. Running a study on the potential re-delineation of bidding zones without defining the methodology can be considered as a serious weakness affecting the overall study but the early implementation exercise will probably provide some useful feedback in that respect.

It is also important that the various possible market effects as well as the costs for network measure (re-dispatching, counter-trading, phase shifters etc.) are concretely assessed and priced for the existing zone delimitation and alternative scenarios. Mere qualitative assumptions are insufficient.

The sensitivity to modelling assumptions should also be taken into account. It is not enough to consider that day-ahead simulations represent a perfect representation of reality (nor the complete welfare or welfare loss). For example the capacity volumes offered to the market in case of different bidding zone configuration might be different in reality. This means that the "demonstrated" benefits based on ex-post simulations may be excessive while a change of bidding zone delineation would be concrete and with immediate effects on liquidity and competition.

It is also crucial that ENTSO-E stipulates the method before the pilot project proceeds with its work and discusses its approach with all stakeholders, including market participants.

10) ***In the process for redefining bidding zones configuration, what do you think are the most important factors that NRAs should consider? Do you have any other comments related to the questions raised or considerations provided in this consultation document?***

As previously mentioned, a number of factors are important when considering such important changes as a potential redefinition of bidding zones.

That being said, we would of course recommend a particular focus on market efficiency, sufficient stability of price zones and market integration, since congestion management and limiting the impact on TSOs' organisations and activities are not European objectives per se and can be managed through other means.

Also two important factors seem to be ignored or misunderstood in the consultation document:

- Insufficient understanding of the economic benefits of larger zones and of the negative impacts of smaller zones and probably overestimation of the estimated benefits,
- Overestimation of to the costs of redispatch and insufficient consideration of other TSO tools for congestion management, such as cross border redispatch and counter-trading, topology measures, coordinated use of phase shifters, etc.

A. Insufficient consideration of the economic benefits of larger zones and of the negative impacts of smaller zones

The consultation paper shows an insufficient consideration of the benefits of larger zones on liquidity and well functioning of both wholesale and retail markets, and similarly underestimates the negative impacts of smaller zones and the difficulty to maintain a liquid forward wholesale market in smaller zones or liquid forward cross-zonal hedging products for these smaller zones. This is already a reality in some market areas today and an evolution towards smaller zones under these conditions would not be in line with the CACM Framework Guidelines and the draft Network Code, which is explicitly based on the understanding that the delineation of bidding zones has a relevant impact on liquidity, competition and social welfare.

EFET is therefore concerned that the review process will focus on technical aspects and will not take the economic effects sufficiently into account.

Firstly, EFET has concerns with the competition assessment sketched by ACER in the consultation paper. The paper states that locational market power is inherently present in the electricity market. It is clearly wrong to imply that larger price zones do not allow for more competition than smaller zones (and also very questionable whether smaller bidding zones would result in more volumes of cross zonal hedging instruments being issued by TSOs).

In smaller bidding zones, fewer generators have more market power whenever interconnectors between the bidding zones are congested (and the market zones are therefore split).

One of the benefits of larger zones is that even if there was some increased locational market power (which is not sure), this would have no effects on market results. This allows the wholesale market to function undistorted, with beneficial effects on competition. Obviously there are limits to this, especially in case of structural congestions, but the benefits associated with a large liquid market should easily overcome the costs of using network constraints management tools, which will be used only for the hours for which real physical constraints will appear whereas "market constraints" would be systematic when applied in market simulations being made well ahead of real time and before taking into account variations due to the intraday market and to balancing and the update of generation and load forecast.

Indeed EFET would see this role of maintaining the integrity of bidding zones as a core competence of the TSO in facilitating the market.

By contrast a separation of the market into the zones on the basis that internal links are sometimes congested seems a disproportionate way to deal with the issue of congestions. Splitting bidding zones into smaller zones will inevitably form a significant barrier to cross border competition, particularly if limited transmission capacity is made available and there are no forward transmission rights to hedge the basis risks between zones.

Secondly, it must be stressed that a re-delineation into smaller price zones will generally negatively affect liquidity.

To that extent we do not understand ACER's claim that only the overall liquidity of all zones covering a given territory is relevant if trading between zones is organised through implicit auctions or market coupling. This approach seems disconnected from reality according to our members' experience.

However as pointed out above, liquidity is defined as a level of trading allowing buying and selling with minimum price disturbance at any time. The market must have the ability to discover a "fair" price" in any situation and not only when there is no congestion. We do not agree that the use of mechanisms for implicit allocation of capacity between bidding zones will make for the liquidity and quality of orders loss since there may be frequent times when transmission capacity volumes are insufficient to allow significant amounts of liquidity in one zone to be "exported" to others.

Even if interconnectors are efficiently used through implicit mechanisms at the day-ahead and intraday timeframe, a market split will occur if the interconnection capacity is congested. In these situations, generation and demand can only participate in their local market and not the territorial market and anyone who is participating from outside that zone will be exposed to basis risks. The forward market will also reflect this congestion risk and the likelihood of splitting. As a consequence, market participants' ability to rely on the market will be impaired.

B. Overestimation of costs of redispatch

It is important to note that redispatch is not the only network constraint management method and is not always needed either. When this is needed due to physical congestions, economic costs occur even if the congested lines are managed explicitly or implicitly between two bidding zones.

Indeed, because there will be a lack of cross-zonal capacity, the (more efficient) power plant in zone A cannot supply customers in zone B. Therefore, in zone B another (less efficient) power plant must be dispatched instead. If there are separate zones, costs are borne by end-consumers in zone B through higher energy prices. If there is only one zone, these costs are socialized through the network tariffs. But the costs to the economy are the same.

We also view the argument that redispatching could have a negative welfare effect because network operators do not pick the optimal power plants in the merit order in the various zones as invalid, because:

- other low-cost congestion tools also exist, such as topology measure and phase shifters,
- TSOs can also potentially use counter-trading, although counter-trading would be less efficient than cross-zonal redispatch due to the fact that with cross-border redispatch TSOs can select the generation or load assets which have the most impacts in relieving the congestion, in addition to ranking their costs,
- simulation at the day-ahead stage of physical flows on all network elements remains a forecast, which will be updated in intraday. Smaller bidding zones would arguably limit market transactions that should not be limited, with better insight and without security margins,
- TSOs should rather be incentivised to further develop their congestion management tools and to develop coordinated cross-border tools, in order to better guarantee the integrity of bidding zones, to lower congestion costs, to decrease reliability margins, to better guarantee firmness and to ensure the most efficient market-based selection of resources, based on their ranking taking into account their efficiency and costs.

In this context we struggle to see how efficient decisions and overall analysis can be made if the basic initial assumptions and orientations are distorted, flowed or inadequately formulated.

C. Need for stakeholder involvement and sufficient lead time before any change is considered

This is also why EFET would like emphasise that market participants must be much more involved in the analysis and should have access to the various methodologies and assumptions.

Also, any possible change of zones should be announced well in advance with a lead time of at least four to five years.

It may also be noticed that reviewing bidding zones delineation on a very frequent basis will probably be of no interest for many regions. When a review is performed, it should be handled with care and should take into account all structural underlying elements and consequences (costs and benefits). A revised bidding zone delineation should only be proposed when the benefits very clearly outweigh the costs.

For all the above reasons and for transparency reasons we would highly recommend multiple interactions with market participants who will be the first impacted by potential redefinition of bidding zones.

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Annex: Bidding zones in the Iberian Peninsula

Focusing on the Iberian Peninsula, the EFET affiliates apply for a review of the current arrangements, where two bidding zones (Spain and Portugal) currently exist, but the interconnection is seldom saturated, in order to explore the possibility of joining both zones together.

The Iberian Peninsula is currently divided into two bidding zones, corresponding to Spain and Portugal, under the operation of REE and REN respectively. The annual demand in Spain is 248 TWh, while in Portugal is 49 TWh and the mixes are not so different, except for the nuclear production, which in Spain averages 22% of the total energy supply.

Since the beginning of the Iberian Market (MIBEL) in 2006, increased price convergence has lead to a situation in which currently (2013) less than 11% of the hours show a price spread. The amount of energy that would have to be redispatched in these hours to achieve a single price averages just 259 MW. The bigger differentials arise in periods with very high hydro and wind production (as it was the case in March 2010, January 2012 and April 2013), because of the high penetration of these technologies in the Portuguese generation mix and the combined effect of interconnection capacity reductions.

The forward markets quote only products indexed to the Spanish price. In 2010 and for the first time, forward trading volumes outweighed the physical demand, reaching as much as 272 TWh in 2012. There are no similar hedging opportunities in Portugal, where suppliers partially hedge using the products linked to the Spanish price and accepting the basis risk. REE auctions FTRs twice a year, but the amount is just 400 MW and the product is not traded in secondary markets.

Introducing a single price zone in Iberia with a coordinated redispatch procedure right after the day-ahead market has to be based on a cost-benefit analysis. The following benefits should be considered:

- It eliminates the basis risk when trying to hedge Portugal in the forward markets, fostering competition in the supply business in Portugal.
- It will further improve competition in the Iberian market, with the main utilities having a smaller share of the production in the integrated area.
- It will not introduce any of the distortions mentioned in the article referred in the consultation[8] , as the costs of redispatch will not be socialised among the countries, bearing each TSO the cost of the redispatching needed in its own area.
- The coordination of the redispatch actions will eliminate some distortions, as it is the case for the preventive capacity reductions introduced by the TSOs in the day-ahead market during the periods of high hydro production.

[8] Scott M. Harvey and William W. Hogan, Nodal and Zonal Congestion Management and the Exercise of Market Power, January 10, 2000