CONSULTATION RESPONSE

ENSTO-E consultation on the bidding zone review

Brussels, 4 September 2024 - Energy Traders Europe welcomes the opportunity to provide comments regarding the ENTSO-E consultation on the bidding zone review (BZR). We appreciate the extensive work carried out by the TSOs and the consultants and the engagement in the Bidding Zone Review Stakeholder Group over the last two years.

Bidding zones are a core element of the European electricity market design. They define the zones withing which market transactions are unconstrained. At their borders, cross-zonal electricity trades and exchanges are organised based on available transfer capacities calculated by TSOs.

The definition of bidding zone boundaries is therefore a question of major relevance for the market and requires profound analysis. Alongside the assessment of current and forecasted congestions on the network, proper attention needs to be paid to safeguarding and improving the functioning of the internal electricity market.

This second bidding zone review started on 8 August 2022 after an ACER Decision[1] with a target year of 2025. This review, unlike the first one, only considers bidding zone splits in France, Germany, Italy, Netherlands and a reconfiguration for Sweden. It is important to note that this review misses the opportunity to analyse the effect on both network management and market efficiency of merging bidding zones in the same way it does so for splitting them.

On a general level, we favour stability in the configuration of bidding zones along the lines of long-standing structural congestions. This certainty and continuity are essential to underpin cross-border competition, liquidity in the forward, day-ahead and intraday wholesale power markets. Liquid wholesale markets are key to manage and reduce risks for market participants, and in turn reduce the cost of trading electricity for the benefit of consumers.

Stable, liquid markets also contribute to a positive climate for investments in generation, storage and demand response that are necessary to secure our electricity supply. And they help foster innovation and the development of new contracts, such as PPAs that are essential for the energy transition.

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1 https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER%20Decision%2011-2022%20on%20alternative%20BZ%20configurations.pdf

Stability and certainty in the delineation of bidding zones is particularly important in the current period of regulatory change for the market, with many new features being implemented and discussed such as 15 minutes market time unit in day-ahead, intraday and in the imbalance settlement period, Nordic day-ahead and intraday flow-based market coupling and a forward market design revision.

Key messages

Decision makers should consider:

- Preserving the liquidity and the functioning of our internal electricity market to match production and demand at the least cost for consumers, including across borders
- Ensuring stability and predictability in the delineation of bidding zone with at least five years implementation lead-time, to reduce transition costs
- Promoting optimal grid usage and, where needed, expansion to make the most of the investments needed for the energy transition and European industrial competitiveness.

Specific comments on the transition costs study

1. On costs

a. Do you consider the estimated range of transition costs reasonable and feasible? Please indicate why or which part of the estimate of transition costs you consider (not) reasonable. Please specify in your answer if you are referring to all configurations or to a specific one

The survey-based estimation model might be insufficient, as noted by the study itself. Evaluations should be based on established models and standard costs (e.g., the cost of renegotiating a PPA or a forward contract multiplied by the operations in each area). Survey estimates are highly dependent on the respondent's perspective, which could lead to significant under- or overestimation by wholesale operators.

Given the restricted dataset available and the uncertainty in cost inputs, the resulting transition costs estimates are subject to significant limitations.

Furthermore, changes to asset value, uncertainty, regulatory risk for investment decisions, and opportunity costs are not included in the transition cost calculation. These factors are relevant to market participants and can be a multiple of the aforementioned values. Ignoring these aspects weakens the transition cost results which would likely be much higher if all such impacts would be considered.

Additionally, the interpretations of cost definitions were challenging, and the data was not subjected to any audit beyond a plausibility test. As noted, "The heterogeneity of estimates highlights the significant uncertainty prevalent in transition cost estimates for BZ configurations." Based on this uncertainty, it is impossible to assert that the estimated range of transition costs is reasonable and feasible.

Despite the limited response to the questionnaire and therefore limited dataset available for quantitative analysis, it is clear that a reconfiguration of bidding zones – especially in geographies with no previous changes in delineation – has sizeable transition costs. This should warrant additional caution when interpreting and using the results.

The transition costs arising from multiple bidding zone splits was left out in the study. This could reinforce the idea that the costs might be closer to or even above the upper end of 2.5 bn EUR of what the consultants and TSOs estimate.

Comparability with the US bidding zone reconfiguration transition costs (i.e. ERCOT) should be dismissed due to the different definition of transition costs and what costs market participants face in the different market designs (i.e. nodal vs zonal).

b. Which mitigation measures, e.g. by TSOs, regulators, policy makers or NEMOs, could decrease transition costs in general? Do you have experiences from previous bidding zone reconfigurations?

The transition costs linked to the reconfiguration of bidding zones itself should not be underestimated, and properly considered. Hence, priority must be given to solutions with a positive or limited negative impact on the market:

- Ensuring that all technologies contribute to system flexibility and that the bidding zone delineation is conducive to fast storage roll-out and more demand response alongside the development of power generation.
- Enhancing grid usage through improved TSO-TSO and TSO-DSO cooperation, cross-border redispatch and cost-sharing arrangements, and advanced cross-capacity calculation processes.

Where appropriate, and in particular where long-standing physical congestions occur, grid expansion can also be a solution, as it lowers redispatch costs. A reconfiguration of bidding zones should only be decided if and when other lower cost, lower impact solutions prove less efficient from both perspectives of network management and market efficiency.

c. Considering the impact of the lead time on the transition costs: What mitigation measures to decrease these costs do you consider reasonable and feasible and how much, in your estimate, would they decrease the costs (in %)?

It is difficult to provide a reliable prediction. Generally, however, the shorter the lead time the more impactful the disruption, and the transition costs to be significantly higher. In any case the liquid traded horizon (up to 5 years on the most liquid markets) must not be disturbed. Lead times of at least five years will allow market participants to better plan for such disruptive change and thus limit transition costs. Longer-term contracts such as PPAs may still be negatively affected considering their much longer tenure (5, 10, sometimes up to 15 years).

d. Do you expect other type of transition cost that are not covered by the definition used in the study which was based on the bidding zone review methodology?

Estimating transition costs is very difficult for market participants as it depends on a number of factors. Some of these factors are internal, such as the complexity of the existing IT infrastructure, the balance between OTC and exchange contracts affected by such changes, and internal change management processes.

Other factors are external and depend on the response of market participants to such changes, including the uncertainty of where other market participants (counterparties to specific transactions) will be obtaining electricity from the grid following the bidding zone reconfiguration and whether contracts can be successfully renegotiated without the need for legal arbitration. This is particularly relevant for PPA contracts which might need to be renegotiated or even terminated and replaced by new ones. Still, these can reflect significant risks for market participants, creating uncertainty and resulting in value losses.

These factors will lead to different outcomes depending on the precise delineation of bidding zones. The more zones that are created, the higher the amount of internal change requirements as well as the risk regarding the contractual counterparty portfolio.

From our perspective these cross-commodity risks and impacts have not been addressed in the bidding zone review but create a significant risk for market participants and investments in the energy transition.

2. Implementation and timeline

a. What do you consider an appropriate minimum implementation lead time of a new bidding zone configuration? Please explain why you consider this to be a minimum

Five years would be the minimum implementation lead time to avoid impacts on the correlated futures and options contracts and to what would happen to the open interest of those contacts.

Most forward contracts have a maturity of maximum three to five years in the current context of electricity markets. It should be noted that the change will nonetheless affect (positively or negatively) existing investments (generation plants, storage assets, demand-response providers) which have a longer amortisation period.

Also, the development of long-term power purchase agreements (PPAs) for renewable electricity, usually concluded for a period of five to fifteen years, will be particularly affected by changes in bidding zones delineation.

b. What are practical considerations that impact the minimum implementation lead time?

Technical amendments to local legislation and methodologies may take a long time after a decision on a bidding zone reconfiguration. This will impact market participants ability to hedge until all secondary regulation is completed.

Furthermore, time should be allotted to thoroughly test and implement IT systems. New products, price curves, analysis tools, etc. will need to be programmed, tested, implemented by all market participants, TSOs and trading venues.

Also, all the transparency needed (including Flow Based domain) for a bidding zone reconfiguration would be required and published on time. Furthermore, a parallel run should be mandatory before any effective bidding zone reconfiguration.

c. What is your experience of previous bidding zone reconfigurations on the implementation and timeline?

The Germany/Austria split announcement was published with a two-year lead-time (on 28 October 2016, effective 1 October 2018), short of the five years we consider the minimum lead-time needed to ensure no open interests are affected by a split.

Furthermore, the methodology of the splitting was not published until very late in the process, some fundamental market design features remaining unknown until three months before the split. This led market participants scrambling to re-arrange their hedging strategies at very short notice. Market participants' trading activities were left exposed until far too late to the effects of the reconfiguration.

d. Are there any other potential changes in the market design that could affect the transition costs of a bidding zone reconfiguration or the implementation and timeline? Why and how would they affect the transition costs and the implementation and timeline?

New offshore bidding zones could affect the transition costs of a bidding zone reconfiguration or the implementation and timeline. This would have deserved more analysis in this review. Risk management and future financing of renewable projects could raise the transition costs further.

3. Please provide ***any other practical considerations*** *on transition costs and implementation and timeline and comments you may have on the transition cost study*

Transition costs also arise because resources are concentrated on a complex project (bidding zone reconfiguration), taking away resources from TSOs, NEMOs and market participants to work on other priorities such as grid extension and improvement of wholesale markets and balancing mechanisms.

The greater complexity in forecasting prices and grid flows makes investment decisions during the implementation period challenging, e.g. for PPAs. This further slows down the needed investment into renewables and the technologies needed for the energy transition.

The choice to change the bidding zone configuration should be made on a solid basis, including studies that can provide reliable quantified estimates or supplement them with qualitative elements where numbers fall short.

The current study does not provide such a basis, with insufficiently reliable quantitative estimates and no qualitative supplements to correctly frame or interpret them. It is likely that the actual costs will be closer to or even hight than the upper end of the spectrum.

Moreover, it is not clear how the conclusions of this study will be incorporated into the broader Bidding Zone Review process or how the transition costs will be weighed against the 21 other parameters investigated.

On a final note, if the long-term stability of zonal configuration is not ensured the possibility of periodical changes will weigh on the cost of trading in the long run, to the detriment of end-consumers. Indeed, market participants will start pricing the risk of renegotiation or early termination in their contracts (forwards and PPAs).

Specific comments on the liquidity and transaction costs study

1. On the impact of bidding zone reconfigurations on liquidity and transaction costs

a. What do you perceive to be the impact of the proposed bidding zone reconfigurations on liquidity and transaction costs in comparison with the status quo configuration?

Our high-level qualitative assessment should be an integral part of, but should not replace, the quantitative analysis that ENTSO-E is expected to perform on market efficiency in the different bidding zones re-delineation scenarios.

Stakeholders have attributed high priority to market liquidity in the analysis, reflecting the importance of bidding zone (re)configurations for the wholesale and retail market. It is positive that it is reflected in multiple indicators in this review such as: bid-offer spreads, trading volumes, churn rate, open interests, market depth, risk premiums and time to maturity.

In the BZR methodology criteria, liquidity and transaction costs are grouped, and the BZR methodology focuses on liquidity rather than transaction costs.

We focus on liquidity in the different wholesale timeframes:

	Germany split	Fance split	Italy split	Netherlands split	Sweden reconfiguration
Liquidity in Forward / future market	**Strong decrease** Splitting Germany into two or more bidding zones means the German market is likely to no longer serve as a reference and pool of liquidity for the whole region. We expect a sharp decrease in liquidity in forward trading for DE in all reconfigurations. This will also have a negative on market participants of adjacent markets that have, until the split, traded in Germany as a reference market. Unfortunately, the study has not assessed the impact of a reconfiguration on neighbouring markets.	**Strong Decrease** Considering the relatively small size of the French East market, we do not expect it to develop a liquid local forward market. The loss of liquidity in the German forward market may, however, lead to a slightly less bleak picture for the French East market than if Germany had remained one single bidding zone. However, France West market participants are likely to remain in the position to rely on imperfect hedges (or "dirty hedges") to mitigate price and volume risks. This will increase the cost of hedging in France West, as well as the cost for the development of long-term projects.	**Decrease** Considering the relatively small size of the IT 2 market, we do not expect it to develop a liquid local forward market.	**Decrease** Considering the relatively small size of the North zone with low generation capacity, we do not expect it to develop a liquid local forward market.	**Stable** Stable Considering the merger of two bidding zones, albeit the potential for a separate Stockholm region bidding zone, we do not expect overall liquidity on the forward market to be hampered.
Liquidity in day ahead market	**Decrease** Liquidity is expected to decrease on the	**Strong Decrease** Liquidity is expected to	**Slight Decrease** Liquidity is expected to	**Decrease** Liquidity is already very low in the day-ahead market and expected to	**Slight increase** Liquidity is expected to rise if existing congestions in SE3 are

	German North and South DA market. Also, this market will be negatively affected by an imbalance between a large power in generation fleet (incl. RES-E) in the North and strong demand in the South.	decrease sharply on the French West and East DA market. Price sensitivity on the French West and East market will sharply increase, which even with market coupling will negatively affect the French West and East DA market (incl. OTC) directly.	slightly decrease on the Italy North DA market, mainly as a result of market design obligation choices.	reduce even further as a consequence of splitting.	alleviated, with increased cross-zonal capacities to be made available to the market (ie. more imports from Finland and increase exports to Norway/Denmark).
Liquidity in intraday market	**Decrease** **DE North**: Liquidity is expected to decrease on the German North ID market. Also, this market will be negatively affected by an imbalance between a large power generation fleet (incl. RES-E) and limited demand. **DE South:** Liquidity is expected to decrease on the German South ID market. Also, this market will be negatively affected by an imbalance between a limited power generation fleet (incl. RES-E) and strong demand.	**Strong Decrease:** Liquidity is already poor on the French ID market, mainly as a result of market design choices. It is expected to further decrease.	**Slight Decrease** Liquidity is expected to slightly decrease on the Italy North ID market, mainly as a result of market design obligation choices.	**Decrease** Liquidity is already very low in the intraday market and expected to reduce even further as a consequence of splitting.	**Stable** Liquidity is expected to rise if more cross-border capacities are available due to improved network management. However, the introduction of flow-based market coupling in the Nordic region in Q4 2024 has raised concerns about reduced intraday capacity. It is therefore difficult to say something meaningful for the time being.

b. Do you agree with the conclusions on the liquidity and transaction costs in alternative bidding zone configurations? Please indicate why you consider the conclusions (not) reasonable. Please specify if you are referring to all configurations or to a specific one.

i. Remarks to the conclusions on the short-term timeframe

We generally agree with the conclusions on the liquidity and transaction costs on the short-time frame and we appreciate that ID churn rates were included as an additional element beyond the ACER Methodology.

Yet, the analysis mainly focuses on the DA market and further analysis of liquidity changes on the efficiency of intraday markets and balancing mechanisms should have been conducted, as these timeframes are becoming increasingly important with the growing penetration of renewables, storage and demand response. In fact, lower liquidity and smaller zones may increase balancing costs because the asset distribution among zones is scarcer, creating possible difficulties for TSOs to access resources.

Considering the important effects of bidding zone reconfiguration on balancing costs, market participants should be informed and should be able to comment the study of factor number 15 "Impact on operation and efficiency of balancing". We also argue that this factor should be quantified and consulted upon.

We warn against the risk of greater market concentration following bidding zone splits. If bidding zones are split, market concentration is likely to increase and, even though it remains a hopeful aspiration, cross-border trade may not be sufficient to counterbalance this effect and bring back market concentration to more acceptable levels.

We also disagree with the conclusion that market participants that will with positions in more than one bidding zone after a split will necessarily engage in trading on the market. It is also possible that market participants will drastically reduce or change their trading and business activity due to the increase in transaction costs.

Overall, we see in theses alternative bidding zones, which are mainly splits, that there may be stronger price reactions to additional producers or consumers. This increases the uncertainty about expected revenues or costs for investors and consumers on the short-term and long-term timeframe. This in turn may impact the required investments of renewables, storage and demand response and increase the cost of the transition.

ii. Remarks to the conclusions on the long-term timeframe

We have more concerns on the conclusions on the liquidity and transaction costs for the long-term timeframe. An important caveat is that the report focuses on each of the BZs individually and thus does not account for potential cross-border effects apart from proxy-hedging to the degree possible. To approximate the relationship, proxy-hedging was parametrised through the explanatory variables "price difference to German futures" and "correlation with German spot market prices". Germany was assumed as reference point because of its market liquidity.

While the regression results are inconclusive about the relevance of proxy-hedging for liquidity overall, this is the reality of today European electricity markets that allows for sophisticated risk management and flexible hedging. The impacts seem to be underestimated in the study.

In general, creating more zones in a market reduces trading opportunities as the upfront network capacity limitations are always defined on assumptions in the future that may or may not occur.

c. What is your experience of previous bidding zone reconfigurations on the impact on liquidity and transaction costs?

Lessons can be drawn from the German-Luxembourg-Austrian split, where liquidity for both short-term and long-term products decreased: Germany-Luxembourg eventually recovered some liquidity, though pre-split levels were never fully restored. In contrast, the Austrian bidding zone has struggled with low liquidity and high costs, as Austrian participants trade in Germany, facing additional fees and risks.

Further lessons could have been drawn from Italy and Sweden bidding zone splits that happened within a Member State.

d. What effects on intra company transactions do you expect from a bidding zone reconfiguration?

Many of the effects affecting external transactions also affect intra company transactions: the delivery point of the commodity may need to be redefined and operational procedures put in place to deal with the transportation. The transportation risk has to be allocated commercially and may change the economics around the transaction. In the case of renewable power production, previously "green" electricity may then become "grey", which would undermine the fundamental economics of the original transaction.

e. Do you think that after a reconfiguration, the hedging opportunities would or would not suffice in certain alternative configuration(s)? Please specify the respective alternative configuration(s) you are referring to and explain how you come to this conclusion. Does it differ under current market design or with mitigation measures in place? If so, please specify.

A reconfiguration will reduce proxy hedging opportunities. The liquid futures market in Germany was one of the reasons why some market participants managed to face the 2022 energy price crisis well.

Companies that had not hedged for the long term had to pay the strongly fluctuating electricity prices on the spot market. Today, most neighbouring market participants hedge themselves i the long term on the stable futures market in Germany.

f. Do you expect additional impacts of the proposed bidding zone reconfigurations on liquidity and transaction costs that were not addressed in the draft report?

Market efficiency does not stop at liquidity. We expect impacts on competition, both at the wholesale and retail levels. We appreciated that ENTSO-E conducted proper scrutiny under the market concentration indicator.

However, a better metric on entry/exit activity and competition would be one that measures how easily market participants can take the decision to enter or exit a market based on commercial consideration, and if regulatory and administrative barriers are reasonably low. This could have been easily obtained from the ACER reports and give a better picture of the bidding zone reconfiguration liquidity and transaction costs.

We also remain concerned about the view that liquidity losses caused by a bidding zone split can necessarily be compensated by higher cross-zonal capacities.

While it is already not certain that a new bidding zone configuration resulting in higher cross-border capacities will ensure more hedging opportunities that fit market participants' needs, there is also no reason to assume that higher cross border capacities will compensate for the liquidity losses incurred in one or more of the markets that have been split.

We may expect additional impact on intracompany transactions and oversight/compliance costs due to the bidding zone splits.

Other additional costs could arise from spillover effect in other markets such as OTC, PPAs that should be highlighted in the study and in the recommendation to the Member States. Furthermore, the study should have addressed other effects such as cross-border impacts, market participant behaviour, and the impact on future renewable energy projects.

2. On mitigation measures

a. What risks or adverse impacts on liquidity and transaction costs do you anticipate with the bidding zone reconfigurations?

i. on short-term markets

Lower liquidity and smaller zones increase balancing costs, as the asset distribution across zones is eliminated. The negative impact of higher balancing costs is especially problematic with the higher need for balancing that comes with an increasing share of renewables in the system.

Lower liquidity also impacts investment decisions, particularly for those assets and services that rely extensively on spot markets and balancing mechanisms. Liquid wholesale markets are key to manage and reduce risks for market participants, and thus to allow for timely investments in generation, storage and demand response.

Higher Price Volatility: Increased volatility affects investment decisions and the operation of units with limited reserves, making revenues for peaking generation and demand response units riskier.

Increased perception of risk by operators: resulting in higher "risk premium" and thus higher costs of investments functional to energy transition

ii. on long-term markets

The impact of lower liquidity on long-term markets would lead to significant basis risks when hedging between illiquid and moderately liquid zones. Ultimately, it would lead to increased transaction costs and higher prices for end-consumers. Additionally, projected revenues of existing investments would be dampened by the reconfiguration, and the ongoing risk of future bidding zone changes would drive investors to demand higher risk premiums.

The PPA market would also be negatively impacted. A bidding zone split would divide the PPA market into smaller zones and decrease the potential to enter PPAs in the same zone. This means that this would lead to a more complex set-up if producer and offtaker are in different zones. This results in a basis price risk between zones that cannot be fully mitigated and increases the risk costs. Hence, PPAs would become more costly.

Further, the development of the PPA market would be negatively impacted if renewable assets are located in lower price zones. The expected lower capture prices make market-based investments into renewables more challenging. Hence, the need for subsidies would be sustained for a longer time, possibly with larger budgets. This would not only increase costs for Member States but it would also be a step back in the market and system integration of renewables.

A fragmentation of zones would have further negative effects in terms of greater uncertainty in estimating resource needs/quotas typically procured long-term through centralized mechanisms (e.g. capacity mechanisms, renewable auctions, storage auctions), with the risk of making the choice of ideal resource location less efficient in the long term.

Moreover, in the long-term timeframe, negative effects and related adjustment costs of existing long-term mechanisms (e.g., RES incentive mechanisms) could be expected, unless mitigation measures are planned and implemented.

b. Which mitigation measures to decrease risk or an adverse impact on liquidity and transaction costs do you consider reasonable and feasible?

i. On short-term markets

Better use of existing infrastructure, including through improved flow-based capacity calculation and allocation in short-term markets could decrease the risk. But it will not cancel the negative – at least transitional – effects on liquidity and transaction costs caused by splitting existing bidding zones.

ii. On long-term markets

To further support the forward market and best enable cross-zonal PPAs, the introduction of long-term transmission rights (LTTRs) that cover the tenure of PPAs (5-10 years+) is fundamental. Increasing the frequency of LTTRs auctions (including capacity re-calculation) on the needs of market participants based on the liquidity of each bidding zone border is another low hanging fruit mitigation measure.

Priority must also be given to solutions with a positive or limited negative impact on the market:

- Ensuring that all technologies contribute to system flexibility and that the bidding zone delineation is conducive to fast storage roll-out and more demand response alongside the development of power generation
- Enhancing grid usage through improved TSO-TSO and TSO-DSO cooperation, cross-border redispatch and cost-sharing arrangements, and advanced cross-capacity calculation processes.

Where appropriate, and in particular where long-standing physical congestions occur, grid expansion can also be a solution in certain cases, as it lowers redispatch costs.

Stable regulatory frameworks are needed, as regulatory uncertainties undermine investors' confidence.

As far as forward market enhancement is concerned, we are critical of experiments that could damage trading conditions within and across bidding borders, such as the development of regulated regional virtual hubs. We believe they deserve extensive assessment and testing before the idea can be refined and implemented.

c. Liquidity risk is not necessarily distributed equally among market participants.

i. What changes in the distribution of liquidity risk do you expect to result from a change in bidding zone configuration and how would it affect different market participants? Please give an example.

Changes in bidding zone configurations are expected to decrease liquidity and increase transaction costs overall, particularly impacting end-consumers.

ii. Do you think there are risk exposure shifts that need to be mitigated? If so, which mitigation measures do you consider to be reasonable and feasible?

Yes, there are expected shifts in risk exposure due to changes in bidding zone configuration, which could result in varied geographic impacts on electricity prices for end-consumers. A longer lead time before any bidding zone reconfiguration will help mitigate the exposure shifts – though the greater or lower exposure in itself is inherent to the bidding zone modification and cannot be avoided as such.

d. Which mitigation measures both generally and against shifts of risk exposure do you consider to be not reasonable or feasible?

We are critical of the effectiveness of mitigation measures related to Bidding Zone reconfigurations. The expectation that such reconfigurations will reduce the need for redispatch is doubtful. Despite the potential for smaller Bidding Zones to turn unplanned flows into market-controlled flows, the necessity for redispatch will persist due to the inherent volatility of renewable energy production.

3. Practical considerations

a. Which practical considerations do you think could affect the impact of a bidding zone reconfiguration on liquidity and transaction costs?

Introducing a bidding zone reconfiguration with its high complexity in the middle of ambitious net zero targets and power system decarbonisation will dampen the speed of energy transition.

Important market design evolutions are being implemented as we speak (e.g.15 minutes market time unit trading) and should be considered in the study as they would influence the impact of a bidding zone reconfiguration.

Margins required by NEMOs in case of a bidding zone reconfiguration could have an impact on liquidity, market efficiency and transaction costs.

The costs of implementing regulated revenue stabilisation tools like capacity remuneration mechanism and Contracts for Difference in different Member States may also increase in case of reconfiguration.

4. Please provide ***any other comments*** *you may have on the liquidity and transaction cost study*

We appreciate that a broad view of liquidity was taken by the consultants. However a deeper analysis of open interests, bid-ask spread and time to maturity, is necessary to correctly assess how suitable a market is to adequately manage risks in the forward time horizon.

To mitigate some of the limitations of approximating the reconfigured bidding zones through indirect indicators (using market size, market concentration, or price correlation), it would have been interesting to also compare bidding zones. It may have allowed to make comparisons and analysis directly on indicators of liquidity, instead of using proxies.

It is not clear how the conclusions of this study will be incorporated into the broader Bidding Zone Review process or how the transition costs will be weighed against the 21 other parameters investigated. A detailed analysis and a consultation on the other indicators should be a workable solution.

In particular, in addition to the aforementioned factor number 15 "Impact on operation and efficiency of balancing" (see answer 1.b.i), factors that are related to the different level of zonal prices that would result from a split, such as factors number 14 "Adverse effects of internal transactions on other BZs", number 16 "Stability & robustness of price signals over time", number 21 "Short term effects on RES integration" and number 22 "Long term effects on low carbon investments" would be worth investigating and consulting upon in the next steps. These factors have numerous impacts among those already mentioned in this text, for example the one on PPAs.

Further questions

1. In the course of the BZR, as foreseen in ACER decision 11-2022, TSOs will also investigate two combinations of bidding zone reconfigurations for Central Europe. What do you consider to be the impacts of more than a single bidding zone reconfigured at the same time in terms of:

a. Liquidity and transaction costs

We are unable to answer this question as it is purely theoretical and dependent on a number of unknown factors, such as market liquidity, availability of transmission capacity, and the ability and appetite to renegotiate supply contracts and prices.

On a theoretical level, more than a single bidding zone configured at the same time will raise liquidity and transaction costs. It should therefore be avoided.

b. Transition costs

We are unable to assess in detail hypothetical changes to bidding zone configurations and their impact on transition costs, particularly since this would require hypothetical discussions with contractual counterparties. Even if such numbers could be derived, we would highly doubt their relevance and reliability given the many uncertainties. Furthermore, we believe that effects of bidding zone delineations other than transition costs are much more relevant, such as the impact on the value of assets, investor certainty, prices, and liquidity.

On a theoretical level, more than a single bidding zone configured at the same time will raise liquidity and transition costs. It should therefore be avoided.

c. lead time

see our answer above under (a)

d. any additional practical considerations

see our answer above under (a)

2. Considering the different potential reconfigurations: are you of the opinion that any implementation of a reconfiguration assessed in this bidding zone review should be undertaken simultaneously or stepwise? If stepwise, then how should the steps be defined?

The only stepwise implementation case in Europe comes from Italy when it performed a national bidding-zone review, pursuant to article 32(1)(d) of the CACM Regulation, which was launched in 2018 and resulted in a two-step reconfiguration of the Italian bidding-zones. In the first step, three of the four "virtual" bidding zones were suppressed as of 1 January 2019.

In the second step, implemented in 2021, one region was transferred from the CNORD bidding zone to the CSUD bidding zone and the SUD bidding zone was split with the creation of a new Calabria bidding zone, merging the remaining "virtual" bidding zone into it.

It is difficult to recommend a simultaneous or stepwise approach for this review, if needed at all, and it should be carefully considered because of the much more extensive impact on cross-border trade and market efficiency in general. Implementation should therefore take at least a five-yeas lead time as argued before if a decision is taken.

3. Please share any additional practical considerations you may have (apart from the timeline and liquidity and transition costs which are covered by previous questions).

If and when a decision to redefine the boundaries of bidding zones is taken, decision-makers should be attentive that the process of changing bidding zones delineation takes many years for decision-making and implementation.

In the meantime, the grid and the market situations change and the assumptions that were used when reviewing the zones will likely prove different in real life. A regular review of the network and market conditions during the bidding zones redelineation implementation is necessary to mitigate the risk of sudden price shocks and incoherent redelineation in the end.

The lower predictability in forecasting prices and grid flows makes financing decision during the reconfiguration period challenging. This may slow down the needed investment into renewables and the technologies needed for the energy transition.

4. What effects on Power Purchase Agreements (PPAs) and other contractual arrangements not covered by the report on liquidity and transaction costs do you expect from a bidding zone reconfiguration?

The PPA market would be negatively impacted. A bidding zone redesign would divide the PPA market into smaller zones and decrease the potential to enter PPAs in the same zone. This means that this would lead to a more complex set-up if producer and offtaker are in different zones. This results in a basis price risk between zones that cannot be fully mitigated and increases the risk costs. Hence, PPAs become more costly.

The development of the PPA market is further negatively impacted if renewable assets are located in lower price zones. The expected lower capture prices make market-based investments into renewables more challenging. Hence, the need for subsidies would be sustained for a longer time, possibly for larger budgets. This not only increases costs for the Member States but is also a step back in the market and system integration of renewables.

Smaller market participants may also face higher transaction costs due to a bidding zone reconfiguration when it comes to PPAs.

5. What alternative policy measures could be implemented to achieve the potential benefits of a bidding zone reconfiguration?

We recognise the need for locational signals in the power system to align physical grid constraints with market outcomes. This is especially true with increasing grid congestions, driving high redispatch volumes and costs.

The challenges in the grid can be solved through physical expansion: more lines, more storage, more electrolysis, more demand response, and better use of the existing grid infrastructure are needed.

TSO-TSO and TSO-DSO coordination and better use of distributed energy sources will also play a key role in solving congestions.

Differentiated grid tariffs or locational components in subsidy schemes could also be an alternative policy measure to achieve the potential benefits of a bidding zone reconfiguration.

The ability of market participants to hedge price risks in the internal electricity market can also be improved by adequately implementing the long-term measures that are already included in the recent Market Design reform (e.g. national guarantee schemes for PPAs, longer maturity LTTRs, etc.).

Contact

Lorenzo Biglia
Manager for European Electricity Markets
E-Mail: l.biglia@efet.org