ACER AND CEER DRAFT POLICY PAPER

ON THE

FURTHER DEVELOPMENT OF THE EU ELECTRICITY FORWARD MARKET

FOR CONSULTATION

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CONSULTATION

The European electricity stakeholders, regulators and policy makers are continuously finding shortcomings in the electricity forward market functioning, which appears to be struggling with many problems such as insufficient liquidity, accessibility, competition and transparency as well as concentrated market power. In the last fifteen years, the day-ahead and intraday markets underwent a significant revision, harmonisation and integration with the introduction of single day-ahead and intraday coupling. While the forward market received a bit less attention in this period, regulators and policy makers are now aiming to revisit the efficient functioning of the electricity forward market with the aim to address the problems that have accumulated or have never been resolved in the first place.

In this draft policy paper, ACER and CEER have attempted to identify the main problems experienced in the EU's electricity forward market and identify possible solutions that policy makers could introduce to tackle and address these problems. This is followed by a qualitative analysis and some preliminary conclusions regarding the most preferred policy options.

ACER and CEER are seeking the views of stakeholders on all aspects of the draft policy paper. In particular, stakeholders are invited to provide their views to identified problems, the set of identified policy options as well as to the analysis and preliminary conclusions.

Based on the outcome of the consultation, ACER and CEER will perform further analysis and evaluation of the possible policy options. If this evaluation confirms the assumed improvements for the electricity forward market functioning, ACER and CEER may recommend amendments of the applicable legal framework in a way to accommodate one or several policy options.

1. EXECUTIVE SUMMARY

The EU transition towards carbon neutrality and other structural shocks in the past few years increased the uncertainty about the future electricity prices. This renders the focus on the forward electricity market much more important to be able to provide some stability to stakeholders when making their investment and trading decisions.

In this paper, ACER and CEER revisit the functioning of the electricity forward market in the EU. We identify that existing electricity forward markets in the EU suffer from a number of problems which prevent achieving the objective of an effective and efficient electricity forward market. These are insufficient liquidity, accessibility, competition and transparency as well as concentrated market power.

In the short term markets these problems have been largely addressed with the help of market coupling (simultaneous matching of buy and sell orders from different markets and available cross-zonal capacity allocation between these markets). Market coupling successfully integrated national short-term markets to operate as one single integrated market. Although the existing long-term cross-zonal capacity allocation does integrate forwards markets to some degree, we find that there is much room for improvement in the way these capacities are used to further integrate forward markets. We identified eight different problems, which are the main reasons why forward markets are not achieving the objective of providing effective and efficient hedging opportunities to market participants.

In order to address the identified problems and achieve the objectives, ACER and CEER propose several improvements to the electricity forward market. Most of these improvements relate to better allocation of long-term cross-zonal capacities in a way that integrates national forward markets into a more integrated electricity forward market.

First, ACER and CEER propose to harmonise the assessment and decisions by regulatory authorities by which the need for regulatory intervention in the electricity forward market is identified and a decision on an intervention is made.

Once the decision on the intervention is made, ACER and CEER identify three promising policy options for the type of regulatory intervention aiming to address the identified problems with better allocation of long-term cross-zonal capacities. These are (i) allocation of zone-to-hub Financial Transmission Rights by TSOs (ii) market coupling with Contracts for Differences and (iii) market coupling with energy futures. All three options involve allocation of long-term cross-zonal capacities by TSOs (either explicit or implicit) in timeframes up to three years ahead of delivery. At this stage a more detailed analysis and discussion are needed on the selection of these three options, namely their true potential to improve the electricity forward market functioning as well as the implementation and operation efforts and costs compared to the benefit they would bring.

In case TSOs allocate long-term transmission rights, ACER and CEER also recommend that these are allocated in a form of FTR obligations and not FTR options or PTRs.

2. INTRODUCTION

In the European Union, the electricity market design is based on bidding zones within and between which market participants can trade electricity in different markets for different timeframes. In the forward market timeframe, trading occurs from several years in the future up to two days ahead of delivery. The forward market allows market participants to stabilise and hedge their future cash flows and thereby secure their businesses against the risks of future price changes. The EU electricity market is undergoing a transition to carbon neutrality and the market has experienced quite a few structural shocks in recent years. This increases uncertainty about the future and renders the focus on the forward market all the more important.

The European electricity forward market appears to be struggling with many problems such as insufficient liquidity, accessibility, competition and transparency as well as concentrated market power. While the day-ahead and intraday markets already underwent a significant revision, harmonisation and integration with the introduction of single day-ahead and intraday coupling, regulators and policy makers are now focussing on the further development of the forward market. The only regulatory intervention at EU level, which is the issuing of long-term transmission rights ('LTTRs') by TSOs, is not the product of careful evaluation of market needs, but rather the remnant of the very beginnings of cross-border trade in the EU where TSOs started to explicitly allocate long-term capacities for trade between Member States. While the focus of LTTRs has gradually shifted from mere capacity allocation to cross-zonal hedging (by increasing the firmness of these rights and the introduction of the use-it-or-sell-it mechanism), the intervention itself remains essentially the same and its appropriateness has not yet been properly reviewed.

This policy paper aims to revisit the functioning of the electricity forward market in the EU. It first aims to define the objectives and characteristics of a well-functioning electricity forward market to be able to evaluate possible improvements against these objectives. Then the paper identifies several shortcomings of the current electricity forward market. The next chapter sets out policy options for possible improvements and regulatory interventions. This is followed by an analysis of the policy options. The paper ends with conclusions and concrete recommendations for improvements of the EU electricity forward market and improvements of the relevant legislation.

This paper outlines ACER's and CEER's perspectives and views on the future development of the EU electricity forward market. It does not aim to objectively quantify and back up all the positions expressed by the regulators. Rather it aims to trigger a discussion among policy makers and stakeholders with general policy considerations, outlined in a concise and reader-friendly manner.

3. OBJECTIVES

In this paper, we assume that the key objective of the electricity forward market is to enable market participants to hedge the risk of their uncertain future cash flows (arising from electricity production, consumption and trading) in timeframes far ahead of delivery. More concretely, this means that in a well-functioning electricity forward market, **each market participant is able to hedge its exposure**:

(a) **effectively (objective 1)**, in the sense that the available hedging products:

- (i) can provide effective hedge against the risk;
- (ii) for each bidding zone (regardless of its size); and
- (iii) in all timeframes ahead of delivery; and

(b) **efficiently (objective 2)**, in the sense that hedging products are available:

- (i) at competitive prices (low bid-ask spread, low risk premium); and
- (ii) in a way that is efficient for market participants to contract them.

Regarding the locational nature of hedging, the price risks fundamentally arise from the uncertainty of zonal prices – these are therefore the primary price risks. On the other hand, cross-zonal price differences arise from zonal price risks – these are therefore considered as the secondary price risks. Therefore, if zonal price risks can be effectively hedged directly, there is no need for specific cross-zonal price hedging products.

Regarding the timeframes, we make a distinction between the timeframe up to 3 years ahead of delivery and timeframe beyond three years ahead. We assume that the forward timeframe up to 3 years ahead is dominated by demand for hedging driven by operation namely electricity consumption and generation. Here, consumers selling their products or services ahead of time are interested to hedge the costs of electricity consumption and producers procuring their fuels ahead of time are interested to hedge the revenues of electricity generation. Beyond the 3-year timeframe, the interests of consumers and producers to hedge operation diminishes significantly and what remains is the interest to hedge investments, dominated mainly by generation investments. The investment driven hedging is beyond the scope of this policy paper and is (to be) covered by another policy paper.

4. LITERATURE REVIEW

The broader context of forward markets is to hedge the risk of the uncertain prices and cash flows. In short term electricity market, these prices have a strong locational dimension, mainly due to congestions. How these congestions are managed has a strong impact on short-term operational efficiency of the market, but also on hedging solutions. A common pattern found across all electricity markets is that hedging requires some sort of aggregation of supply and demand for hedging across larger areas (aggregation of nodes into zones or hubs or aggregation of zones to hubs) and organising forward market around such aggregates. The risk not covered by the aggregate hedging products (the difference between aggregate prices and specific locational price, i.e. 'the basis risk') is then covered by complementary hedging products.[1]

In the European electricity market, the aggregates are constructed around bidding zones (or combination of bidding zones), whereas the basis risk can be covered by various transmission rights or Contracts for Differences ('CfDs'). Their application in different regions or borders in EU is summarised in the study of Economic Consulting Associates (2015).

The literature on electricity forward markets can be broadly fitted into three classes. The first studies the overall market design as a balance between the construction of aggregates and managing the basis risk. The second class of literature focuses on the functioning of the aggregated forward markets and the third class covers the functioning of the basis risk hedging.

Harvey et al. (1996) proposed a non-regulated aggregation hubs based on market preferences and node-to-node FTRs to cover the basis risk between the nodes. As node-to-node FTRs may be quite illiquid due to large number of combinations, another option is to define ex-ante the exact aggregation and this allows to provide all FTRs from each node against the same predefined aggregation hub. This significantly reduces the number of different FTRs. The problem of how to construct such hubs in an optimal way was analysed by Borisovsky et al. (2009), having in mind that well-defined hubs may not need additional basis risk products if correlations between the hub price and nodal prices are high. All references to nodes above of course also apply to zones.

The second class of literature on the functioning of forward markets at aggregates is most widely represented, as it is the main forward market which covers the majority of risk for most market participants. This area focuses more on liquidity, competition, market structure and price dynamics and is less relevant for market design choices.

In the third class of literature on hedging basis risk we find mostly literature on transmission rights issued by system operators and other financial products between market participants, such as Contracts for Differences. The CfDs in the form of EPADs (Electricity Price Area Differentials) have been implemented in the Nordic electricity market in 2000. Since then, they were under constant scrutiny, since the Regulation (EU) 2016/1719 prescribes transmission rights as the standard basis risk products. Among others, Hagman and Bjørndale (2011) and Spodniak et al. (2017) questioned the superiority of Nordic CfDs in comparison with FTRs.

In the area of transmission rights, physical transmission rights are inherited from the liberalisation of the market in EU. Over the last 30 years, many authors assessed and demonstrated analytically the superiority of financial over physical rights (Batlle López et al 2014), (Joskow and Tirole, 1998) and (Harvey et al., 1996).

Lastly, the financial transmission rights are vastly present across the globe in both zonal and nodal market designs and are considered to be a central piece of the market designs (London Economics International LLC, 2020), (Electricity Authority, 2019). Two central features of

[1] Complementary in the sense that they complement the aggregate hedging products to cover the basis risk that is not covered by these aggregates.

FTRs is the revenue adequacy for the TSO and full financial firmness for market participants (Hogan, 2013).

In the current context of the energy transition towards renewable electricity production and the need to ensure security of supply, speeding up the electricity market integration and enhancing the integration of the forward markets is key (ACER, 2022). Having longer term products is one way to support these objectives (Beato, 2021). However, ensuring the short-term efficiency while maintaining a sufficient liquidity remain a key concern to solve in the continental EU market. A study of the European Commission (2021) concludes that having smaller bidding zones would provide this short-term efficiency and that enhancing the FTR products with a zone-to-zone or zone-to-hub functionality could address the hedging of basis risk. This specific FTR design is supported by Hogan (2002) and already implemented around the world (PA Knowledge Limited, 2003). Pushing towards a maximal efficiency of system operation, Kunz, et al. (2016) study this concern in a nodal representation of a European network and conclude that FTRs help to mitigate the higher distributional impacts caused by a smaller granularity of network representation in the market design.

5. TERMINOLOGY AND PROBLEM DESCRIPTION

5.1 Terms used

Throughout this document, the following terms are extensively used. They are therefore defined in this section to clarify their meaning.

Long Term Transmission Right (LTTR)

This term refers to a hedging contract between a TSO (or Single Allocation Platform (SAP)) and a market participant for the right to transmit electricity between two network locations based on cross-zonal capacity allocation. A TSO (or a SAP) is always a central counterparty to the holders of LTTRs. See Sections 6.4.1 and 6.4.3 for more explanation.

Contract for Difference (CfD)

This term refers to a hedging contract traded at a power exchange which provides the holder the obligation to pay or receive the price difference between two underlying day-ahead (spot) prices. A power exchange (or its clearing house) is always a counterparty to holders of CfDs. The EPAD system currently present in the Nordic region is a form of CfD contracts.

Hub

This term refers to the aggregation of several locations where electricity prices are established (e.g. bidding zones) into a single aggregated price and location (based on agreed rules). A hub could, for example, be a region with a hub price defined as the weighted average price of every bidding zone within this region.

Market coupling

This term refers to a market mechanism in which energy products in different bidding zones are matched simultaneously with cross-zonal capacities.

Futures

This term refers to standard energy futures contracts traded at power exchanges which provide the holder the obligation to pay or receive the day-ahead (spot) price. A power exchange (or its clearing house) is always a counterparty to holders of Futures.

Forwards

This term refers to non-standardised energy contracts between market participants to buy or sell energy at a specified price at a future date. They differ to futures mainly in customisation, settlement and counterparty risk.

Secondary market

This term refers to a market that allows the market participants to exchange products acquired in a previous (primary) market.

Basis risk

This term refers to the risk remaining due to a mismatch between the exposure and a given hedging product. It implies that that the price to which one is exposed might not move in total and steady correlation with the price underlying the hedging product.

5.2 Problem description

In the current European internal electricity market, we have identified a number of inefficiencies in the functioning of the electricity forward market. In this paper, we focus only on the problems that are affecting the objectives described in Chapter 3, namely the possibility of all market participants to be able to hedge their exposure effectively and efficiently.

Problem 1 (lacking liquidity in small bidding zones): The most important problem that we identify is the lack of adequate hedging possibilities (in terms of the objectives described above) in many small bidding zones in Europe.

While market participants in some bidding zones are able to find fairly liquid hedging products in their bidding zones at competitive prices, many other bidding zones have not developed liquid forward markets, which meet the above objectives. In particular, forward markets in smaller bidding zones suffer from poor liquidity, high bid-ask spread and the problem increases with longer maturities. This is the result of conflicting goals between short term market efficiency, which requires efficient management of congestions and sufficient liquidity for hedging which requires aggregation of larger areas regardless of congestions. An absence of such aggregation in the long-term timeframe results in less liquidity in small zones. The reasons may not lie only in the size of bidding zones, but also in other design issues (network-oriented bidding zone setup as well as historical developments) or interventions (such as subsidies on fossil, renewable and nuclear investments), which protect market participants from risks and thereby take away their need or incentive to hedge. Market participants in such illiquid bidding zones need to either pay higher premiums for products at illiquid markets or find other alternatives such as forward markets in neighbouring Member States and possibly complement them with transmission rights, if such neighbouring market products do not provide an efficient hedge. In this respect, market participants in small bidding zones face discrimination in market access and a non-level playing field, as they are not in an equal position compared to market participants trading in large bidding zones where liquidity is higher. This problem negatively affects the Objective 1.ii, which subsequently affects Objectives 1.i and 2.i.

Problem 2 (hampering forward markets): An alternative hedging strategy, i.e. buying futures and forwards from neighbouring markets and LTTRs to the home market, further strengthens the liquidity of the neighbouring market (due to more demand) and hampers the liquidity in the home market (due to less demand). The alternative hedging strategy provided by LTTRs therefore damages the liquidity of the home forward market products, rather than strengthening it. This problem currently negatively affects the Objectives 1.ii and 2.ii, which subsequently affects Objectives 1.i and 2.i.

Problem 3 (no continuous/secondary market): The alternative hedging strategy with LTTRs is not available on a continuous basis to support the continuous nature of electricity trading, in particular in forward timeframe. This is because LTTRs are auctioned only at specific times and no secondary market exists, where market participants could buy LTTRs at the time when they settle a new trade which exposes their position. This problem currently negatively affects the Objectives 1.iii and 2.ii, which subsequently affect Objective 1.i.

Problem 4 (barrier to bidding zone reconfiguration): In Continental Europe, each bidding zone is trying to develop its own zonal forward market, whose success depends on the size of the underlying bidding zone, but is significantly affected in case of re-configuration of a bidding zone. In particular, a negative impact on forward market liquidity is identified as probably the most significant barrier to reconfiguration of biding zones, which is important to facilitate short-term market efficiency. Therefore, a reform of the forward market design should make the forward market liquidity less dependent on the size of the bidding zones. This problem only has an indirect contribution to the Objective 1.ii and therefore on Objective 2.i.

Problem 5 (inadequate maturities): The alternative hedging strategy with LTTRs is limited only to shorter maturities, namely year ahead (yearly LTTRs auction about one month before the start of the delivery year) and month ahead (monthly auction about few weeks before the start of the delivery month). This does not enable such a strategy to be used for longer-term deliveries or other within-year deliveries (e.g. quarters or seasons), which are generally available at liquid forward markets. This puts market participants, which can only use the alternative strategy, in an even worse position compared to participants which can rely on zonal forward market for hedging without the need for LTTRs. This problem negatively affects the Objectives 1.iii and 2.ii, which subsequently affect Objective 1.i.

Problem 6 (inefficient products): LTTRs are currently offered only in a form of physical transmission rights ('PTRs') or financial transmission rights ('FTR') options which offer only a hedge against a positive market spread. On the one hand, this is a flexibility appreciated by many market participants, as they are not obliged to pay the market spread to TSOs in case it is negative. On the other hand, it reduces the volumes of offered LTTR products (because the LTTRs in the opposite direction cannot be netted in terms of allocated cross-zonal capacity), makes the hedging more expensive (as the prices for LTTR options are theoretically higher than for obligations), limits the possibility to have zone-to-hub LTTRs products and makes forecasting of prices more complex (as these products are not directly comparable with the prices of futures contracts that are obligations by default). This problem negatively affects the Objective 2.ii, which subsequently affect Objective 1.i.

Problem 7 (undervaluation of capacities): LTTRs are continuously being undervalued. All the analyses of ex-post risk premia performed by regulators and TSOs in the past have shown that the prices of LTTRs are below the market spread (see for example Section 6.2.2 of ACER Market Monitoring Report from 2015[2]), whereas in theory, if these products would be used for hedging purposes, the LTTR prices should be above the expected market spread (including

[2]https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER%20Market%20Monitoring%20Report%202015%20-%20ELECTRICITY.pdf

also a risk premium)[3]. While this effect is very low on some borders, it is significant on many other borders. Consequently, by issuing LTTRs, TSOs are receiving less congestion income compared to if the long-term capacities would instead be allocated only in the day-ahead timeframe. This loss of congestion income has an impact on the maximisation of cross-zonal capacities, network investments and, in the last instance, on network tariffs. This problem negatively affects the Objective 2.i.

Problem 8 (non-coordinated assessments and decisions): The criteria for NRAs to evaluate the sufficiency of hedging possibilities and subsequently decide whether TSOs should offer LTTRs or provide some other hedging alternatives, is neither clear nor harmonised. This makes the application of this flexibility provided by the EU legislation confusing and lacking proper justification. Consequently, TSOs may auction LTTRs on bidding zone borders even where there is no absolute necessity (e.g. between Germany and France where liquid forward markets exist on both sides of the border) or they abstain from being involved even in cases where such need exists. This problem only has an indirect contribution to the Objective 1.ii.

Another problem identified by some regulatory authorities is the efficiency of capacity allocation in flow-based approach, which favours large bidding zones and bidding zones at the perimeter of regions (the problem known as flow factor competition). While this problem may worsen the accessibility of LTTRs in small bidding zones in the flow-based approach, it is not specifically addressed here, as it is not unique to long-term capacity allocation and may need to be addressed by other more structural measures.

6. OPTIONS TO ADDRESS THE PROBLEMS

The first part of this chapter introduces two general policy changes which are independent from any other options and are considered to be beneficial based on the experience and past discussions among regulators, TSOs and stakeholders. The subsequent sections describe policy changes with different options focusing on three categories of problems, namely (i) is the regulatory intervention needed, (ii) what kind of regulatory intervention is most suitable and (iii) if TSOs issue transmission rights, what should be the form of these transmission rights.

6.1 Basic policy changes – no regret improvements

The following section introduces basic policy changes independent from other options not implying substantive changes for the current forward market design. Those were identified to directly address well-known problems, where possible, with limited resources and impact.

6.1.1 Alignment of CNTC and FB requirements in LT and DA timeframes

The current FCA Regulation defines the coordinated net transmission capacity ('CNTC') approach to capacity calculation as a standard approach, whereas the flow-based approach may be used subject to efficiency assessment. Nevertheless, the implementation of long-term capacity calculation methodologies has revealed that the underlying reasons for choosing the

[3] A negative risk premium could occur only in case of the seller of the contract is more interested to hedge than the buyer, but in case of LTTRs, TSOs are not active price setters and have no interest to hedge themselves.

flow-based approach is the same in all timeframes, namely the interdependence between bidding zone borders in a CCR. For this reason, both CCRs that are applying the flow-based approach in day-ahead and intraday timeframe (i.e. Nordic and Core CCR) have chosen this approach for the long-term timeframe as well.[4] This is because it has been demonstrated that CNTC approach is not feasible for highly meshed networks and interdependent borders. From this perspective, it makes sense to equalize the requirements for flow-based and CNTC approach in all timeframes.

6.1.2 Monthly products at 1YA auction

The current FCA Regulation provides a framework under which the LTTRs are issued at yearly auctions (with yearly baseload products) and monthly auctions (with monthly baseload products). During the implementation of the FCA Regulation, stakeholders proposed to TSOs and regulatory authorities to introduce monthly baseload products also at yearly auctions. This means that yearly auction would allocate both yearly baseload product as well as twelve monthly baseload products. This proposal seems a no regret measure that can be introduced in any of the policy options which include allocation of long-term cross-zonal capacities.

6.2 The need for intervention

6.2.1 Option 0: Status quo: Regionally different approaches

The current FCA Regulation and Regulation EU 2019/943 provide a framework for TSOs to issue LTTRs or to apply equivalent measures that enable to hedge price risks across bidding zone borders, except in cases where regulatory authorities identify that the forward market provides sufficient hedging opportunities in the concerned bidding zones.

This framework resulted in three different regimes across Europe:

- The long term transmission rights in the form of PTRs or FTR options are issued in capacity calculation regions of Core, Italy North, South East Europe and South-West Europe regions as well as on bidding zone borders FI-EE, EE-LV, DK1-DE, DK1-NL, DK2-DE and DK1-DK2. These transmission rights are issued within the framework of the Joint Allocation Office and Harmonised Allocation Rules as established by the FCA Regulation.
- In Nordic CCR TSOs currently issue any long-term transmission rights. LTTRs only on DK1-DK2 border. On the remaining borders, regulatory authorities decided that forwards and futures linked to the Nordic system price forward market as well as CfDs are sufficient to provide hedging possibilities to market participants active in the Nordic bidding zones.[5]
- In bidding zones within Italy, the TSO allocates the so-called Contracts Covering the Risk of Volatility of the Fee for Assignment of Rights of Use of Transmission Capacity (‘CCCs’) which are a form of FTR obligations linked to a hub price (which is the Italian

[4] See ACER Decision 14/2021 and ACER Decision 16/2019. Both decisions essentially concluded that CNTC approach is not feasible for highly meshed network, such as Nordic or Core CCR, because of interdependency between borders, making the flow-based approach the only possible choice.

[5] Recently some Nordic regulatory authorities are discovering that some bidding zones may not provide sufficient hedging opportunities. For example, in March 2022 the Finnish regulatory authority informed ACER that it has identified insufficient hedging opportunities in the Finnish bidding zone.

PUN price) and the volume of allocated CCCs from different bidding zones is limited with long-term transmission capacity between bidding zones.

The regionally specific regime mainly results from the historical development on how regional markets have been setup before the integration into EU market. In particular, the different approach to bidding zones (i.e. the Nordic and Italian market favouring small bidding zones to manage congestions more efficiently) is a major contributor to a different forward market design.

Benefits of this option

The benefit of this option is that it allows flexibility for national regulatory authorities to tailor the hedging market according to their views and assessment of the specific market needs.

Drawbacks of this option

The drawback is that these assessments are not harmonised, transparent and may lead to different decisions ending up in different regimes, which may not necessarily be justified by the underlying market fundamentals.

6.2.2 Option 1: Coordinated assessment and decisions on hedging opportunities

In this approach, TSOs will be involved in facilitating hedging opportunities, unless the market effectively provides other hedging opportunities that are sufficient to meet the objectives. In order to decide whether the TSOs can be exempted from issuing LTTRs, an assessment of the market's ability to provide such opportunities needs to be done first. Such assessment should be performed by regulatory authorities at least at regional or optimally at European level (possibly under the ACER framework). The assessment should use transparent and precise metrics to measure the functioning of the forward markets and possible inefficiencies, which would require regulatory intervention. An assessment should be repeated on a regular basis and may also be done at request of market participants. The outcome of the assessment should be consulted with market participants.

After the assessment is finalised, regulatory authorities need to make a decision whether and which kind of regulatory intervention is needed. Such a decision should be done in a coordinated way in each CCR for all bidding zones or bidding zone borders of a CCR. This coordinated decision does not exclude the possibility of different measures at different bidding zones or borders if all regulatory authorities agree.

In order to harmonise the metrics of the assessment (e.g. bid-ask spread, churn factors) and criteria (e.g. thresholds) for the decisions of regulatory authorities, ACER could issue an EU-wide recommendation that would aim to harmonise standards and principles for the assessment and decisions. Such recommendations would not be binding and would thus allow regulatory authorities to deviate in specific cases when duly justified to accommodate local or regional specificities.

Benefits of this option

Since regulatory intervention would be applied only in those areas where it is indispensable for long-term hedging purposes, administrative effort and costs for TSOs would be decreased to a minimum level. The same would apply for regulatory authorities as the number of administered terms and conditions or methodologies will be reduced, and repetitive assessments and decisions will become easier with the harmonization facilitated by ACER's recommendation. The assessments and decisions would become more transparent, comparable and efficient than national ones, especially when they need to be repeated or updated regularly.

Drawbacks of this option

This approach reduces the national flexibility in the assessments and decisions because they need to be coordinated and agreed at regional level. Market specificities such as the share of consumers on fixed price contracts, hedging possibilities outside organised markets and size and price correlation between bidding zones make it difficult both to calculate comparable parameters and to decide on the appropriate common thresholds.

Mandatory and regular assessment in all CCRs where no such assessments have been made so far could mean less regulatory intervention and as a result, market participants might lose the opportunity to acquire hedging products from TSOs and rely purely on financial markets for hedging which may be more costly.

6.2.3 Option 2: Mandatory intervention

This option assumes regulatory intervention by default in all regions. It means no case-by-case regional or national assessment of hedging opportunities is needed. It therefore assumes that besides the non-regulated forward market, TSOs would always be involved by issuing LTTRs or supporting hedging opportunities in some other way.

The benefit of this option is that regulatory authorities would not need to perform regular assessment of sufficient hedging opportunities and deciding on interventions. The drawback is that sometimes the intervention would be in place even when there is no need. In such cases it could be argued that this brings unnecessary costs and burden and could perhaps also damage the forward market.

6.2.4 Option 3: No regulatory intervention

This option does not pursue any TSO or regulatory involvement in supporting the forward market. It is based on the trust that the market would provide sufficient hedging opportunities reflecting the supply and demand for hedging. This option assumes that if there is demand for hedging there will surely be a supply for it and liquidity will develop.

A well-functioning forward market is characterized by at least the following features:

- It facilitates price discovery (transparency);
- It is characterised by effective competition, diversity of counterparties and low market concentration;
- It provides effective long-term hedging opportunities and is sufficiently liquid;
- It has low entry and transaction costs; and
- It supports contestability in the wholesale and retail electricity markets.

These conditions could be achieved in a market model similar like any forward market where financial derivatives are standardized and traded in an exchange or over the counter. In this case, the demand for hedging is the driving force which will attract sufficient supply to cover the demand. The price of these products will therefore reflect the demand and supply of hedging. If the market works efficiently, the bid/ask spread of the hedging product is expected to converge to zero, reflecting zero transaction costs and, therefore, efficient hedging. Any temporal lack of supply will increase the bid/ask spread and this is expected to gradually attract additional supply.

Even if this option assumes no regulatory intervention, it still allows power exchanges to facilitate the liquidity with market makers. This possibility exists in all options and is independent of the discussion about regulatory interventions in this Section. Such market making would be outside regulatory control and without any regulated cost recovery. It is left completely to the discretion of each power exchange. See Section 6.3.7 for more description of the market making function.

Benefits of this approach

The main benefit of this approach is that market participants are able to meet their hedging requirements in a cost-efficient way, provided that the pre-conditions of a well-functioning forward market are in place.

Drawbacks of this approach

The market outcome in terms of effectiveness and efficiency could be affected in case of failure on the above-mentioned features. In practice, effective competition is limited to markets with high liquidity with enough supply and demand of financial derivatives. In the absence of effective competition, cost-efficient hedging as described above would not be possible.

Another challenge that prevents well-functioning forward markets are exchange membership costs, especially for small market participants. In this case, OTC trading is an alternative for market participants. However, the available information to market participants is not as transparent as at the exchange.

In addition, also the predictability of future prices and the volatility of the market are reflected in the risk premium and the bid/ask spread. Consequently, well-functioning forward markets are more difficult to achieve in periods with high volatility. However, this uncertainty remains also when TSOs intervene by auctioning LTTRs or other hedging products.

6.3 Type of intervention

6.3.1 Option 0: Status quo: Bidding zone border LTTRs

The current FCA Regulation provides a framework in which long term cross-zonal capacities are allocated with **explicit allocation** and LTTRs are issued to market participants based on such allocation. These are issued on bidding zone borders (‘BZB’) only, which means only between neighbouring bidding zones which are interconnected. This setup results from historical development where cross-border trading began between neighbouring bidding zones only based on available interconnection capacity. Only after the markets have been properly integrated and especially with the introduction of flow-based capacity calculation, it became apparent that the option to allocate LTTRs also between non-neighbouring bidding zones is also feasible, but is not yet integrated in the legal framework.

For a concrete example on the functioning of this option see Case 1 in Annex II.

6.3.2 Option 1: increased number of allocation and product timeframes

This option is applicable to cases where TSOs allocate long-term cross-zonal capacities and assumes longer-term horizons (up to at least 3YA) and more frequent allocations.

This option takes into account that LTTRs are usually complementary hedging product in the sense that it is combined with forwards and futures traded at financial electricity markets. However, market participants complain that while they are able to trade forwards and futures for several years in advance they are not able to complement them with LTTRs which are offered only one year ahead and just shortly before delivery starts. Such LTTRs therefore fail to support trading and hedging in longer-term horizons. In a similar fashion, (cross-border) Power Purchase Agreements also rely on LTTRs and have significantly gained in volumes over the last years. Those agreements, playing a key role in the development of renewable energy production projects, have typical durations between 5-15 years and would strongly benefit from LTTRs with longer-term horizons.

To address this problem the products issued by TSOs with capacity allocation could extend its time to delivery to meet the market needs. A three-year ahead (3YA) timeframe is often considered as a horizon in which the consumers are strongly interested to hedge, whereas beyond this horizon, the interest decreases significantly. This can be observed in liquidity of forwards and futures traded at financial markets where a significant drop in liquidity is observed beyond the 3YA horizon.

Allocating cross-zonal capacities in longer-term horizons raises concerns on uncertainties in capacity calculation and how much cross-zonal capacity can be offered within such a long horizon. Nevertheless, the following two elements make this problem less of a concern. The first is the use of a statistical approach in the capacity calculation. This avoids the need for detailed network modelling in longer horizons and takes stock of the fact that history reveals there always is some cross-zonal capacity available and the likelihood of no capacity being available is extremely small. Second, the long-term cross-zonal capacities would need to be allocated in a form of financial products, which have no physical impact on the network but only a financial one. In this sense, the regulatory framework should provide TSOs with adequate comfort on cost recovery to cover the risks for those rare cases where allocated long-term capacity would not be available in the day-ahead market and TSOs would thus face revenue inadequacy.

A longer horizon would also imply that cross-zonal capacities would have to be allocated more gradually with smaller quantity for each auction and increasing the total amount closer to the delivery.

Longer term horizon may also require some changes in the rules for settlement and requirements for collaterals. Today, SAP settles long-term auctions income in monthly instalments and remunerates LTTR holders daily at delivery. However, the SAP could apply daily settlement only, where only the difference between the original auction price and day-ahead market spread would be settled at delivery. This could potentially reduce the level of required collaterals.

This option also aims to improve the problem noted by market participants that they enter into long term contracts on a continuous basis, but they are only able to acquire LTTRs in very few occasions. Furthermore, the secondary market for LTTRs has never developed and therefore it is not possible for market participants to use LTTRs to hedge accurately every cross-border trade.

Two elements to improve this discrepancy could be to introduce more frequent auctions and to facilitate secondary market. Regarding more frequent auctions, one option would be to organise monthly auctions for yearly products and weekly auctions for monthly and weekly products.

The secondary market could be improved by (i) more frequent auctions where also market participants could (re)sell their hedging products and (ii) making products more compatible with financial products, such that they can be easily converted and transferred into financial products traded continuously on financial markets. This would require that product obligations, timeframes, deliveries, etc. would be completely the same as for existing standard products traded at financial markets.

An example on the organisation of the auctions could be the following:

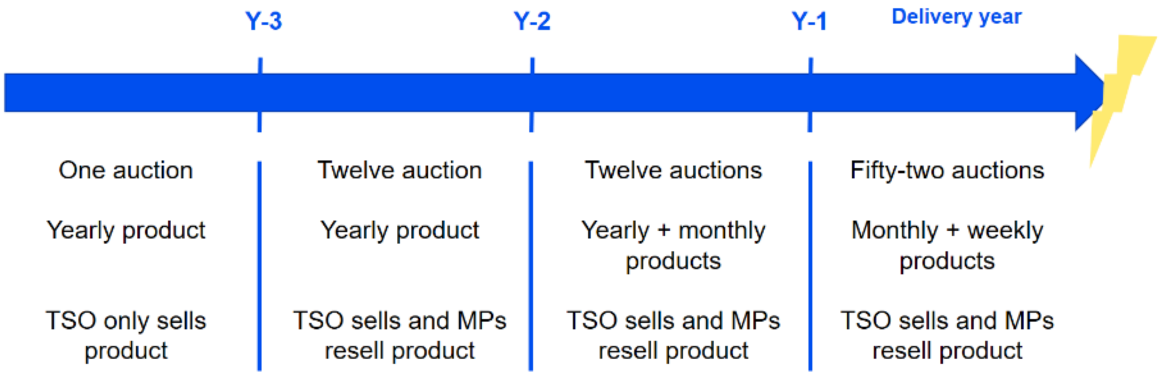

Figure 1: Example of allocation timeframes

This option could lead to less liquidity and competition for cross-zonal capacities due to more frequent auctions, but less participation could be partially offset by the lower quantities being offered. This option would also increase administrative burden of auctioning and facilitate secondary market and thereby increase the costs of SAP.

6.3.3 Option 2: Zone-to-zone LTTRs

This option assumes improvements of the current border-wise LTTRs and expand them to any-zone to any-zone ('Z2Z') LTTR, which entails that bidding is also allowed Z2Z. This option is specifically suitable for flow based capacity allocation, but also possible when CNTC approach is used. Long-term cross-zonal capacities are allocated with **explicit allocation**.

Cross-regional hedging could also be added to this option. This would mean organising cross-regional auctions covering the geographical scope of all CCRs having chosen to rely on LTTRs. The benefits of those auctions lie in the efficiency in bidding for the market participants compared to a regional approach.

For a concrete example on the functioning of this option see Case 2 in Annex II.

Benefits of this option

This option allows more efficient hedging between non-neighbouring bidding zones compared to Option 0, where hedging between non-neighbouring bidding zones with BZB LTTRs is very inefficient and complex as it involves purchasing multiple products in auctions organised at different moments in time. Considering the growth in importance of cross-border power purchase agreements (PPAs), often in countries distant from each other with different renewable energy resources, hedging possibilities between non-neighbouring countries need to be improved.

Drawbacks of this option

While this option does improve hedging possibilities compared to Option 0, it is unlikely to solve (actually it could even exacerbate) the problem of illiquid secondary market for LTTRs because the number of different LTTRs would explode. Similar as Option 0, this option also does not support the liquidity of the forward market, because it still provides alternatives to forward markets and thereby may reduce liquidity in forward markets in small bidding zones.

6.3.4 Option 3: Zone-to-hub LTTRs

This option assumes improvements of the current BZB LTTRs and expand them to zone-to-hub (Z2H) LTTRs, whereas bidding can be both Z2Z and Z2H. Long-term cross-zonal capacities are allocated with **explicit allocation**.

This option allows market participants not only to hedge against price differentials between any two bidding zones, but also to hedge the price of a bidding zone against the price of a hub. The price of the hub could follow the model applied in Nordic or Italy where the price of the hub represents some sort of average price of several bidding zones (this could be the simple or weighted average or unconstrained price[6]) and the number of aggregated zones could be regional (CCR), sub-regional or multiregional. A careful analysis, stakeholder consultation and regulatory approval would be needed before defining such a hub.

The motivation for this option is to aggregate forward market liquidity at a single hub instead of in each bidding zone. Z2H FTRs would then provide a hedging instrument to cover the risk of remaining price difference between the hub and zone price (basis risk). Thus, several small bidding zones could aggregate their supply and demand for hedging in a common hub where liquidity can more likely develop than in each zone separately, whereas big bidding zones which already have liquid national zonal forward market could continue using this market.

Market participants could submit a Z2Z or Z2H orders and the auction algorithm would match the orders in a way that maximises the economic surplus[7] and the total net position of the hub must be zero, whereas the volume of accepted orders multiplied by the corresponding Z2H power transfer distribution factors (PTDFs) would be equal or lower than the remaining available margin on all critical network elements. With this respect, the location of the physical hub against which the PTDFs are calculated is not important as long as each matched Z2H order is complemented by another matched Z2H order and the net position of the hub is zero.[8]

In case a market participant wants to hedge zone-to-zone as in Option 2, it would submit such a Z2Z order. If the order is accepted, such a market participant would receive a portfolio of two Z2H products, namely one Z2H and one H2Z merged into a “combo”.

$$LTTR_{Zone\ A\ to\ Zone\ B} = LTTR_{Zone\ A\ to\ Hub} + LTTR_{\ Hub\ to\ Zone\ B}$$

This option assumes the establishment of price hubs aggregating the day-ahead prices of several bidding zones. It is assumed that such hubs will attract demand for futures and forwards linked to these hubs and that power exchange will offer trading with such futures and forwards without the need for regulatory intervention. The Z2H LTTRs would provide a hedge

[6] Day-head price under assumption of unlimited cross-zonal capacities.
[7] Sum of products of order prices and their accepted volume.
[8] In case of FTR options, separate Z2H and H2Z FTRs are auctioned and each Z2H FTRs needs to be offset by another H2Z FTR of the same volume. In case of FTR obligations, only Z2H FTRs are auctioned and these are, for the purpose of assessing their impact on CNECs, split per direction and their impact is assessed the same way as with FTR options, except that they can be netted.

to cover the remaining risk between the hub price and the price of each individual bidding zone.

In this option, TSOs (or the SAP) would be the counterparty for LTTRs holders. The LTTRs could be resold at the next auction or on the secondary market. At delivery, the SAP would settle with each LTTR holder the difference between the original LTTR price (the price at which the LTTR was obtained) and the day ahead price differential between the corresponding zonal price and hub price. In principle, TSOs would receive the congestion income resulting from the allocation of long-term cross-zonal capacities through such LTTR auction and at delivery pay back to LTTR holders the congestion income received from reallocation of these capacities in the day-ahead coupling. In practice, both financial streams would be netted and settled at delivery.

Cross-regional hedging could also be added to this option. Cross-regional auctions covering the geographical scope of all CCRs having chosen to rely on LTTRs, could be organised. In the situation where Zone A and Zone B do not belong to the same CCR, a market participant wanting to hedge from zone A to zone B would obtain one LTTR from zone A to Hub 1 and one from hub 2 to zone B, while the price difference between the two hubs could be covered either by auctioning LTTRs between these hubs or by buying or selling futures at these two regional hubs.

For a concrete example on the functioning of this option see Case 3 in Annex II.

Benefits of this option

This option allows for a dual type of hedging, namely Z2Z and Z2H. It allows the emergence of forward trading hubs aggregating more than one bidding zone, which should improve the forward market liquidity, compared to a situation where each biding zone would rely on its own zonal forward market.

This option is very flexible to any changes in bidding zones – namely the change of biding zones would have a minor impact on the hub price and the products traded at the hub price would be largely unaffected by such a change. For example, changes of bidding zones in the Nordic electricity market are fairly simple and can be implemented fast due to such a design. The change of bidding zones would only affect the LTTRs in the bidding zones which are directly concerned and thereby the impact is limited to these areas and to the basis risk only.

Furthermore, in this option there is a single LTTR product per bidding zone (Z2Z products can be split into two Z2H LTTRs and resold separately) – this means less products and more likely development of secondary market for them. Furthermore, in case Z2H LTTRs are FTR obligations, they would be financially equivalent to CfDs (and zonal Futures if combined with hub-based Futures), which may be traded in parallel on the power exchanges or OTC. Z2H LTTR holder can sell an equivalent product in the form of a CfD without incurring any additional financial risk. Thereby such LTTRs can facilitate more liquidity in the CfD markets (like the Nordic EPAD market).

Another benefit of this option is that it allows for a unified market model across the whole EU (as Nordic electricity market already has a hub based system which could easily be complemented with Z2H FTRs) and it is suitable for possible future changes towards very small bidding zones (e.g. offshore bidding zones) or nodal market. In such cases these small zones or nodes would hedge with hub-based futures combined with FTRs issued by TSOs.

Drawbacks of this option

The drawback of this option is that it is to a large degree conditional on the liquidity of the hub-based forward market to which the LTTRs are linked. This would mean forward market trading in small bidding zones would need to largely shift to the hub-based forward market. However, if such forward market for the hub does not develop, one could question the added value of this design. Nevertheless, this option would still facilitate Z2Z hedging and the secondary market. Namely, Z2Z combos can always be split and new Z2Z combos can be formed by procuring two Z2H and H2Z LTTRs in the secondary market. Therefore the risk of failure to achieve the liquid forward market at the hub should not be a determining factor in establishing such a model.

This option is also not well suited for facilitating the continuous secondary market for FTRs. While more frequent auctioning would increase accessibility of these FTRs, it is still unlikely that a liquid continuous secondary market would develop for these FTRs. Such a market could only potentially develop if such products would be traded at power exchanges in which case these would be CfDs. However, in case of FTR obligations, market participants could easily arbitrage between both products (e.g. buy FTRs and sell CfDs), without incurring any financial risk. However, FTRs and CfDs would still require separate trading venues, because the counterparty of the FTR holders is always the SAP, whereas for CfDs it is the respective power exchange. This means that market participants active in both would have to provide collaterals to both markets.

Z2H LTTRs as a combination of Z2Z LTTRs

This option presents a specific variant of Option 3 in the way the Z2H LTTRs are constructed and in how the hub price is defined. Hub prices are computed by multiplying the zonal spot prices of the participating zones by a Weight matrix that could be, for example, based on the traded volumes or the electricity consumption of the past delivery period. Similarly, Z2H LTTRs are constructed by summing, in the same pre-determined amounts, Z2Z LTTRs:

$$Price_{Hub} = Weight\ matrix * Zonal\ Price_{Zone}$$

$$LTTR_{zone-to-hub} = Weight\ matrix * LTTR_{zone-to-zone}$$

A market participant having submitted a Z2H LTTRs bid, if selected, will receive a portfolio of Z2Z LTTRs. Later, the market participant has the option to re-sell its Z2H LTTR or to sell the several Z2Z LTTRs of its portfolio. Those Z2Z LTTRs can then individually be sold by market participants in the secondary market.

This option presents similar benefits and drawbacks than Option 3. It however exacerbates the drawback linked to the development of a liquid forward market at the hub considering that the Hub price would be defined based on factors that need to be fixed years ahead of the delivery, whereas in Option 3 the weights for zonal prices can be based on actual traded volumes at each market time unit.

For a concrete example on the functioning of this variant see Case 4 in Annex I.

6.3.5 Option 4: Forward market coupling with CfDs

This option entails defining standard products in a form of CfD contracts linked to predefined hub prices and then cross-zonal coupling with these products with **implicit allocation** of long-term cross-zonal capacities. These CfDs are financially equivalent to Z2H FTR-obligations in Option 3 in the sense that they offer the same hedge between zonal day-ahead price and day-ahead hub price. The only difference to Z2H FTRs is that the counterparty in these contracts would be power exchanges (NEMOs) instead of SAP. Such contracts (although not supported by the allocation of cross-zonal capacities) exist today in the Nordic market, known as EPADs, although there is currently no cross-zonal matching and coupling of such EPADs in the Nordic market. All principles related to hub-based forward market in Option 3 also apply to this option, except that basis risk would be hedged with CfDs instead of FTRs.

This option intends to replicate the market coupling model from the day-ahead and intraday timeframe. This entails the following elements:

- the competent authorities designate one or more nominated electricity market operators for forward timeframe in each bidding zone;
- a harmonised set of CfD which are used in the market coupling (e.g. yearly, quarterly and monthly CfDs);
- the forward market coupling algorithm that matches CfD orders from each NEMO and each bidding zone while taking into account the long term cross-zonal capacities provided by TSOs; and
- the clearing and settlement among NEMOs and TSOs.

Similar to Option 3, this option assumes the establishment of price hubs aggregating the day-ahead prices of several bidding zones. It is assumed that such hubs will attract demand for futures and forwards linked to these hubs and that power exchange will offer trading with such hubs without the need for regulatory intervention. The regulatory intervention would only be applied to facilitate CfD trading and these CfDs would provide a hedge to cover the remaining risk between the hub price and the price of each individual bidding zone.

In this option, NEMOs would collect orders for CfDs from market participants and send them to the Market Coupling Operator ('MCO'). Similarly, TSOs would send long-term cross-zonal capacities to MCO. The MCO would then match all orders from all NEMOs and the cross-zonal matching would need to respect the cross-zonal capacities provided by TSOs. After the orders are matched, the results are provided to NEMOs and TSOs. The market coupling could accommodate yearly, monthly or weekly auctions as well as continuous trading between them. The orders and contracts would need to be directly transferable between auctions and continuous trade such that the contract obtained in the auction can be resold at continuous trade and vice versa.

At delivery, each NEMO will settle with each CfD holder the difference between the original CfD price (the price at which the CfD was matched) and the day ahead price differential between the corresponding zonal price and hub price. In principle, TSOs would receive from NEMOs the congestion income resulting from the allocation of long-term cross-zonal capacities through such forward coupling and at delivery pay back to NEMOs the congestion income received from reallocation of these capacity in day-ahead coupling. In practice, both financial streams would be netted and settled at delivery.

The governance of this option could be similar as for the day-ahead and intraday coupling where Member States or their designated authorities designate or grant a passport to NEMOs for the purpose of forward market coupling. Although these NEMOs would perform competitive tasks, regulatory authorities would need to monitor these NEMOs in their execution of their tasks (i.e. collecting orders, settlement, etc.). In parallel, the monopoly tasks of market coupling operation could be performed by a central entity (which could be a new role for SAP). The oversight of this entity would need to involve all NRAs and/or ACER.

For a concrete example on the functioning of this option see Case 6 in Annex II.

Benefits of this option

The benefit of this option, compared to Option 3, is that it allocates cross-zonal capacities without the need to establish separate markets for FTRs and CfDs. Therefore, CfDs obtained at the auction can be immediately resold in continuous trading (or vice versa) and thus effectively fully close the position. This enables a single market for CfDs, whereas in case of Z2H FTRs, the two markets must remain strictly separated, and only arbitrage between two markets are possible. Market participants would thus be able to obtain all hedging products at a single point, (e.g. single NEMO), which reduces the costs of trading (fees, collaterals).

This option, similar as Option 3 is very flexible to any changes in bidding zones – namely the change of biding zones would have a minor impact on the hub price and the products traded at the hub price would be largely unaffected by such change. For example, changes of bidding zones in the Nordic electricity market are fairly simple and can be implemented fast due to such a design. The change of a bidding zone would only affect the CfDs in the bidding zones which are directly concerned and thereby the impact is contained only to such area and only to the basis risk.

Like in Option 3, a specific challenge is the hedging on the interfaces between regional hubs. Namely, bidding zones which are located in two or more regions would be linked to two or more hubs. One solution would be to enable two or more CfDs for such hubs, while the other solution would be to limit such bidding zones only to one hub, in which case some cross-zonal capacities on the interfaces would not be allocated (for example if FR bidding zone would offer only CfDs linked to Core hub) the long-term cross-zonal capacity linked to SWE hub would not be allocated.

Another benefit of this option is that it allows for a unified market model across the whole EU (as Nordic electricity market already has a hub based system with CfDs) and it is suitable for possible future changes towards very small bidding zones (e.g. offshore bidding zones) or nodal market. In such cases these small zones or nodes would hedge with hub-based futures combined with CfDs facilitated by forward market coupling.

Drawbacks of this option

This option implicitly requires the development of a liquid forward market at the hub to which the CfDs are linked. It therefore assumes that forward market trading in small bidding zones would largely shift to hub-based forward market trading. If such forward market does not develop, these CfDs would have no added value and would be used only for Z2Z hedging.

This option requires a rather complex setup of market coupling, NEMO designation and cross-border clearing and settlement as well as monitoring tasks which would cause an additional administrative burden. While experience, algorithms and entities from day-ahead and intraday coupling would simplify implementation and operation, it is arguably a more burdensome and complex option than Option 3. Compared to Option 5, this option requires the establishment of new CfD products (except in Nordic and Baltic region and inside Italy where these already exist) and is conditional on emergence of liquid forward products linked to hubs. Most likely it would shift existing forwards and futures from all smaller bidding zones to such hubs.

6.3.6 Option 5: Forward market coupling with Futures

This option is similar to option 4, except that the coupling is not organised with standard CfDs, but instead with standard futures contracts which are currently traded at different forward power exchanges. Long-term cross-zonal capacities are allocated with **implicit allocation**. This option does not need a hub and allows the existing forward markets and futures products traded therein to be coupled with long term cross-zonal capacities. Similarly as in Option 4, at the delivery of these forward contracts, the TSOs would cover or receive any net financial income from settlement of such standard futures.

This option therefore aims to provide more liquidity to existing national forward markets by providing a platform where these standard futures products could be automatically traded across the border by taking into account the available long-term cross-zonal capacities. The market coupling could be organised with auctions and continuous trading as in Option 4.

For a concrete example on the functioning of this option see Case 7 in Annex II.

Benefits of this option

The benefit of this option is that it would support existing forward financial markets by providing additional liquidity due to cross-border matching. It therefore does not require any change in the design of existing financial markets, only standardisation of few futures products (e.g. yearly, quarterly and monthly baseload futures). Similarly to Option 4, market participants would be able to obtain all hedging products at a single point, (e.g. single NEMO), which reduces the costs of trading (fees, collaterals).

Drawbacks of this option

The drawback of this option is that it is less flexible to any bidding zone reconfiguration – namely the change of biding zones would still have a significant impact on the forward market as the underlying price would significantly change. Nevertheless, it would still prevent significant loss of liquidity since any loss of liquidity due to reduction of bidding zone size would be compensated by liquidity resulting from cross-zonal matching.
Another drawback of this option is that it is unlikely to be suitable for areas, which already have hub-based forward markets with CfDs. This would mean that the forward market design would remain different in different regions.
Finally, this option is not well suited for future changes in EU electricity market which may at least in some cases converge towards smaller bidding zones (e.g. offshore bidding zones) or nodal market. In such cases developing forward markets for each small zone or node would not make much sense even in the presence of forward market coupling.

6.3.7 Option 6: Market making

This option involves a regulatory intervention, where TSOs do not get involved in any allocation of long-term cross-zonal capacities, but instead they (or NRAs) perform a tender for a market maker function and the TSOs pays the price/fee that the market maker demands for performing such service. The costs of performing this function would ultimately be recovered through network tariffs or other appropriate mechanisms determined by the competent regulatory authorities.

Market makers support exchange liquidity directly, by being obliged to post buy and sell orders with a predefined maximum bid-ask spread and minimum volume. A lower bid-ask spread and increased volumes in order books enable market participants to reduce trading costs and allow then an easier exit or entry into positions. Additionally, higher volumes in order books reduce the liquidity risk for speculative traders, which may in turn increase liquidity further.

The efficiency of market making support depends on the requirements imposed on market makers regarding the bid-ask spread and required volumes. The right level can be decided based on consultation with market participants and analysis of regulatory authorities. The potential market makers are selected based on the price or fee they demand for fulfilling the market maker function during the requested time period. It can be expected that a narrower bid-ask spread and higher required volume would lead to a higher demanded price/fee. As the demanded price/fee depends on market volatility and the risk assessment of potential market makers, the outcome of the selection process is quite uncertain.

Benefits of this approach

The benefit of this option is that it strengthens and increases liquidity in existing forward markets and does not split liquidity by introducing new alternative hedging products. It also allows to tailor this measure only to bidding zones with insufficient hedging opportunities.

Another benefit of enhancing market making is that it does not require changes in the market design and can be implemented within a short timeline.

This option does not expose TSOs to financial risks, except the cost arising from the selection process, which can be capped or the selection can be cancelled or repeated if the costs turn out to be too high. The TSO does not need to take part in the market or become a market participant and has no strategic interest. Compared to other options where TSOs allocate long-term cross-zonal capacities, this option does not entail the risk that the long-term congestion income is systematically lower than if these capacities would instead be allocated only in the day-ahead timeframe

Drawbacks of this approach

Besides the uncertain costs for market making service, another drawback of this option is that it is not an efficient measure in bidding zones with asymmetric production and consumption. A basic strategy for a market maker is to minimise its open position. If a market maker's bid is matched on one side of the order book, the market maker will adjust the order book (to maintain the required bid-ask spread) in such a way that it is more probable that next time a bid on the other side of the order book will be matched and thus reduce the open position of the market maker. This strategy is difficult to execute in a bidding zone with much higher consumption than generation or the opposite. A market maker has in such a bidding zone an incentive to bias its bid-ask spread in such a way that minimal trades are made between the market maker and the dominating side in the bidding zone which fails to achieve the very purpose of the intervention[9].

6.4 Type of products offered by TSOs

This category of policy options identifies options on the type of products TSOs would allocate in case of explicit allocation of long-term cross-zonal capacities. In case long term cross-zonal

9 http://www.nordicenergyregulators.org/wp-content/uploads/2015/12/TE-2015-35-Measures-to-support-the-functioning-of-the-Nordic-financial-electricity-market.pdf and FCA-Konsultrapport-Measures-to-improve-hedging-opportunities-on-the-electricity-market-in-Sweden.pdf (ei.se)

capacities are allocated implicitly via market coupling, the underlying products are by default obligations and these cases are not considered in the following policy options.

6.4.1 Option 0: Status quo (PTRs and FTR options)

The current FCA Regulation provides a framework which enables to issue LTTRs in a form of PTRs with Use-It-Or-Sell-It (UIOSI) principle and FTR options or obligations. However, only PTRs and FTR options are currently used on different borders, whereas FTR obligations are not used on any bidding zone border.

PTRs and FTR options are auctioned on a bidding zone border in both directions (here we call these “oriented bidding zone borders”), i.e. PTR from zone A to zone B and PTR from zone B to zone A.

PTRs with UIOSI are physical transmission rights auctioned at yearly auctions or monthly auctions which give the right to the PTR holder to nominate physically the electricity exchange on the concerned oriented bidding zone border. The UIOSI principle refers to the case when the holder decides not to exercise this right (i.e. not to nominate the physical exchange), the holder receives from the TSOs the market spread (i.e. day-ahead price difference) on the concerned oriented bidding zone border, if positive, for each MW of PTRs it holds. In case the market spread on the concerned oriented bidding zone border is negative, there is no financial exchange between TSOs and PTR holder.

FTR options are financial transmission rights auctioned at yearly or monthly auctions which give the right to the FTR holder to receive from the TSOs the market spread (i.e. day-ahead price difference) on the concerned oriented bidding zone border, if positive, for each MW of FTRs it holds. In case the market spread on the concerned oriented bidding zone border is negative, there is no financial exchange between TSOs and FTR holder.

PTRs with UIOSI and FTR options are financially fully equivalent – they offer the same level of hedging to the holder (except in very specific cases such as scarcity situation). Consequently, most PTR holders decide not to nominate PTRs physically and rather receive the market spread remuneration which makes the use of these PTRs equivalent to FTR options.

6.4.2 Option 1: PTRs and FTR options with reduced firmness

In a coupled day-ahead market the LTTRs are reallocated in the day-ahead coupling and the congestion income from this reallocation is transferred to LTTR holders. This balanced mechanism does not work in the case of a decoupling. Here, LTTR holders are not remunerated with the congestion income from capacity reallocation, because capacity is reallocated through fallback explicit auction, but LTTR holders still receive the day-ahead market spread, which is usually even higher if the markets are decoupled. In addition, remunerating LTTR holders with the market spread provides no incentive to LTTR holders to participate in the fallback explicit auctions. Hence, the congestion income received from fallback explicit auctions is significantly lower than remuneration costs and this financial loss represents a (temporary) financial burden for TSOs and is ultimately recovered via network tariffs.

This option proposes that the LTTR remuneration in the event of a decoupling is not based on the decoupled market spread, but instead on the congestion income collected from the reallocation through the fallback explicit auction.

Benefits of this option

The benefit of such option is that it could provide more incentives to LTTR holders to take part in the fallback explicit auctions which would lead to a more efficient auction outcome and to a lower market spread. It could also reduce financial burden for TSOs and consequently also for consumers paying network tariffs.

Drawbacks of this option

Reducing firmness of LTTRs would contradict the very objective of these products, which is to provide hedging opportunities. Reduced firmness would expose market participants to higher risks, which could make them value these products less and this would potentially result in a loss of congestion income that potentially could on average surpass the loss of TSOs in case of decoupling. This is supported by the fact that TSOs are better able to manage the risks that decoupling events entail than market participants, hence putting this risk on them would lead to worse market outcome than keeping the risk at TSOs. Furthermore, TSOs, together with NEMOs are responsible for market coupling and should have some possibility to impact it. Therefore, it makes sense that, despite cost recovery for such losses, TSOs have at least temporary financial incentives to impact market coupling organisation, such that it minimises the likelihood of such events.

6.4.3 Option 2: FTR obligations

FTR obligations entitle its holder to receive from a TSO a remuneration equal to the market spread if positive or obliging its holder to provide financial remuneration to the TSO equal to market spread if negative. Hence, the settlement of an FTR obligation equals, and will reflect, the average price differential for the delivery period.

FTR obligations are allocated on a bidding zone border (or Z2Z or Z2H) with a standard direction (e.g. from hub-to-zone) and there are no FTR obligations allocated in the opposite direction because it is already covered by the standard direction. They are usually priced lower than FTR options and can also have negative prices.

Benefits of this option

The benefits of FTR obligation is that they offer the perfect hedge against the price differential, they are usually priced lower than FTR options (affecting the size of collaterals), they are more compatible with products traded at financial markets and allow for netting of cross-zonal capacities which allows for higher volume of allocated FTRs. The bidding for FTR obligations is also easier as the comparison with products at financial markets is more straightforward and with less need for complex forecasting of expected day-ahead prices. This is particularly important for bidding zone borders without a dominant direction of the positive market spread.

Drawbacks of this option

The drawbacks of FTR obligations is that they offer less flexibility to hedge only one direction, which may be the preferred type of products for some market participants.

7. ANALYSIS AND CONCLUSIONS

7.1 Available options

In this Chapter we analyse the identified policy options as identified above against the objectives in Chapter 3 and problems in Chapter 5. Where a combination of options is possible and better able to meet the objectives and address the problems we also analyse such combinations.

7.1.1 The need for intervention

In order to comply with the legal framework set out in the Article 9(1) of the Regulation (EU) 2019/943[10], only the options 0 (Status quo) and 1 (Coordinated assessment of hedging opportunities) of Section 6.2 are legally feasible under the existing legal framework. On the contrary, neither the default mandatory TSO involvement nor the default absence of regulatory intervention would comply with Article 9(1) of the Regulation (EU) 2019/943.

Comparing Option 0 (Status quo) and Option 1 (Coordinated assessment on hedging opportunities), Option 0 (Status quo) fails to meet the Objectives 1 and 2. This is because non-coordinated, non-harmonised and non-transparent assessments and decisions of regulatory authorities may lead to situations where they fail to intervene even when the market is unable to deliver hedging products that would meet both objectives. Option 0 (Status quo) also fails to address Problem 7 (undervaluation of capacities). For these reasons, ACER and CEER consider that Option 1 (Coordinated assessment on hedging opportunities) is the preferred option, because it provides for a more coordinated and harmonised approach in the assessment of the forward market and decisions by concerned regulatory authorities. Therefore, the following analysis of the other two categories assumes that Option 1 (Coordinated assessment on hedging opportunities) is chosen for the type of regulatory intervention.

7.1.2 Type of TSO intervention

Seven options are proposed in section 6.3 and analysed in this category:

- Option 0 – Status quo
- Option 1 – Improved allocation and product timeframes
- Option 2 – Zone-to-zone LTTRs
- Option 3 – Zone-to-hub LTTRs
- Option 4 – Forward market coupling with CfDs
- Option 5 – Forward market coupling with Futures
- Option 6 – Market making

Options 0 to 5 represent a gradation of the TSOs' intervention while option 6 can be considered as a different type of intervention by the TSO.

Option 0 (Status quo) obviously fails to address all the problems identified in Chapter 5 as these have been identified in the status quo. Furthermore, in Option 0, small bidding zones struggle with illiquid forward markets and forces market participants to use alternative hedging strategy (see Problem 1) which is available only with year-ahead and month-ahead LTTRs. Option 0 partly contributes to Objective 1.i (because LTTR, once obtained, do provide effective hedge against cross-zonal price risk) and fails to contribute to Objective 1.ii (because some

[10] In accordance with Regulation (EU) 2016/1719, transmission system operators shall issue long-term transmission rights or have equivalent measures in place to allow for market participants, including owners of power-generating facilities using renewable energy sources, to hedge price risks across bidding zone borders, unless an assessment of the forward market on the bidding zone borders performed by the competent regulatory authorities shows that there are sufficient hedging opportunities in the concerned bidding zones.

small bidding zones do not have access to liquid forward market in neighbouring bidding zones) and Objective 1.iii (because the allocation timeframe is limited to one year and secondary market is non-existent). Option 0 does not contribute to Objective 2.i (because it worsens the illiquidity in small zones and thereby not likely to provide hedging products at competitive prices) and Objective 2.ii (because it imposes a rather complex alternative hedging strategy to combine liquid products and (one or several) BZB LTTRs.

Option 1 (Improved allocation and product timeframes) is able to address the Problem 5 (inadequate maturities) because it introduces allocation of cross-zonal capacities in longer timeframes (up to 3 years ahead). This option also includes more frequent auctioning which partly addresses also Problem 3 (no continuous/secondary market). With regard to the objectives, Option 1 is better able to address Objectives 1.iii, 2.ii thanks to the revised timings of the auctions as well as the longer term products. This option is neutral towards other objectives. This option is also not exclusive and can be combined with other options. ACER and CEER therefore support this option.

Option 2 (Zone-to-zone LTTRs) introduces additional LTTRs between non-neighbouring bidding zones. In this regard, it is better than Option 0 and partly contributes to Objective 1.ii. This option may partly address Problem 1 (liquidity in small bidding zones) and Problem 7 (underselling of capacities). This is because it introduces additional hedging possibilities and more competition for LTTRs. However the majority of Problem 1 (liquidity in small bidding zones) and Problem 2 (hampering forward markets) remain unsolved with this Option 2. Further, Option 2 may make Problem 3 (no continuous/secondary market) even worse as it introduces a significant number of new LTTRs (combinations of all zones). This option also does not address Problem 4 (barrier to bidding zone reconfiguration) since the forward markets still relies on liquidity in each bidding zone separately and in isolation. Option 2 is able to partly address Problem 7 (underselling of capacities) as it introduces more competition for LTTRs, but still relies on explicit auctioning and may not address the problem entirely.

This Option contributes positively to meeting Objective 1.i (because LTTR, once obtained, do provide effective hedge against cross-zonal price risk), Objectives 1.ii (because it adds more possibilities to each bidding zone to hedge at LTTR auctions) and is contributing negatively to Objective 1.iii (because even if combined with Option1, secondary market is unlikely to ever develop due to large number of different LTTRs). Option 2 does not contribute to Objective 2.i (because it worsens the forward market illiquidity in small zones and thereby not likely to provide hedging products at competitive prices) and contributes positively to Objective 2.ii by easing the access for market participants to hedging between non-neighbouring bidding zones.

While ACER and CEER generally support bidding and hedging between any two bidding zones, Option 2 is not preferred because it does not address the main problems.

Option 3 (Zone-to-hub LTTRs), similar as Option 2, allows for bidding and hedging between any two bidding zones, but it adds an additional feature, which is the hedging against a hub. This option has the potential to attract much of forward trading from small bidding zones (but possibly also from big ones) in one or several hubs, which has the potential to significantly improve the forward market liquidity. This equalizes the access to a liquid forward market and FTRs to all market participants from all biding zones and thereby addresses the Problem 1 (lacking liquidity in small bidding zones). This option is also able to address Problem 2 (hampering forward markets), since it does not hamper the forward market liquidity but rather strengthens it. Option 3 can partly address Problem 3 (no continuous/secondary market), because these FTRs in case of obligations, are financially equivalent to CfDs and market participants can resell them as CfDs at power exchanges and thereby facilitate continuous CfD market. Option 3 is also addressing Problem 4 (barrier to bidding zone reconfiguration), since the reconfiguration of bidding zones does not hamper the forward market liquidity concentrated at a common hub. Similar as Option 2, this option is also able to partly address Problem 7 (underselling of capacities) as it introduces more competition for LTTRs, but still relies on explicit auctioning and may not address the problem entirely.

Option 3 has a very positive contribution to the Objective 1.i (because LTTR provide effective hedge against cross-zonal price risk, but this option also allows much easier and continuous access to these LTTRs), positive contribution to the Objective 1.ii (because it pools the forward market liquidity to a common hub thereby giving the same market access to all bidding zones) and is indifferent to Objective 1.iii (if combined with Option 1, it can positively contribute to this objective). Option 3 has a very positive contribution to the Objective 2.i (because it facilitates forward market liquidity in a common hub thereby more likely to reduce bid-ask spreads and risk premia) and has a positive contribution to the Objective 2.ii (because it allows easier access to hub-based Futures as well as LTTRs, yet it still relies on separate platforms).

For the above reasons, ACER and CEER consider that this option is one of the preferred options.

Option 4 (Forward market coupling with CfDs) is similar to Option 3 in design and is therefore able to address the Problem 1 (lacking liquidity in small bidding zones), Problem 2 (hampering forward markets) and Problem 4 (barrier to bidding zone reconfiguration). In addition, Option 4 relies on power exchanges to facilitate trade with CfDs, which can be done based on auctions as well as continuous trading. This enables more continuous trading and secondary markets and is therefore also able to address Problem 3 (no continuous/secondary market). Option 4 includes market coupling, which is traditionally able to better allocate cross-zonal capacities compared to explicit auctions considered in Options 0, 2 and 3. For this reason, Option 4 is also able to address Problem 7 (underselling of capacities).

Option 4 has a very positive contribution to the Objective 1.i (because CfDs provide effective hedge against cross-zonal price risk, but this option also allows much easier and continuous access to these CfDs), positive contribution to the Objective 1.ii (because it pools the forward market liquidity to a common hub thereby giving the same market access to all bidding zones) and is indifferent to Objective 1.iii (if combined with Option 1, it can positively contribute to this objective). Option 3 has a very positive contribution to the Objective 2.i (because it facilitates forward market liquidity in a common hub thereby more likely to reduce bid-ask spreads and risk premia) and has a positive contribution to the Objective 2.ii (because it allows easier access to hub-based Futures as well as CfDs, which can all be accessed at a single point of contact).

For the above reasons, ACER and CEER consider that this option is one of the preferred options.

Option 5 (Forward market coupling with Futures) is similar to Option 4, except that the products being subject to market coupling are not CfDs but instead zonal energy futures. As market coupling pools the liquidity of small and big bidding zones into a single integrated market, this option is able to address Problem 1 (lacking liquidity in small bidding zones). This option is able to address Problem 2 (hampering forward markets), because it does not introduce separate hedging instruments but instead relies on existing zonal energy futures. Regarding the flexibility to bidding zone reconfiguration, this option is more flexible to bidding zone reconfiguration than Option 0, because each loss of liquidity inside a bidding zone being reconfigured is compensated by the increase of liquidity arising from market coupling. However, this option is less flexible to a bidding zone reconfiguration than Options 3 and 4, which enable the hub based futures to be unaffected by changes in bidding zones. This option is particularly questionable for bidding zones which are very small (such as offshore bidding zones, or zone consisting of just one or several nodes) and is not ready made for potential change to nodal pricing, like options 3 and 4. Similar to Option 4, Option 5 relies on power exchanges to facilitate trade with futures, which can be done based on auctions as well as continuous trading. This enables more continuous trading and secondary markets and is therefore also able to address Problem 3 (no continuous/secondary market). Option 5 also includes market coupling and is therefore able to better allocate cross-zonal capacities and thereby address Problem 7 (underselling of capacities).

Option 5 has a very positive contribution to the Objective 1.i (because Futures provide effective hedge against the zonal price risks and their access is easier), positive contribution to the Objective 1.ii (because it allows for much better liquidity of Futures in small bidding zones due to market coupling) and is indifferent to Objective 1.iii (if combined with Option 1, it can positively contribute to this objective). Option 3 has a very positive contribution to the Objective 2.i (because it facilitates forward market liquidity in all biding zones and thereby more likely to reduce bid-ask spreads and risk premia) and has a positive contribution to the Objective 2.ii (because it allows easier access to Futures without the need for additional products to cover the basis risk).

For the above reasons, ACER and CEER consider that this option is one of the preferred options.

Option 6 (Market making) is completely different to the other options regarding the type of TSO intervention. While it is able to partially address the Problem 1 (lacking liquidity in small bidding zones), its potential is limited in case of a structural lack of generation/supply or demand in a bidding zone. This option is able to address Problem 2 (hampering forward markets) as it supports the forward market rather than hampering it. This option also supports and facilitates the continuous nature of the forward market (Problem 3 - no continuous/secondary market). Option 6 neither increases nor decreases the flexibility of forward market to a possible bidding zone reconfiguration. Namely when the forward market is based on zonal energy futures, this option does not address the underlying problem of this market being inflexible to bidding zone reconfiguration. It therefore is not able to address Problem 4 (barrier to bidding zone reconfiguration). On the other hand this option is able to address the problem of inadequate maturities by obliging market makers to facilitate liquidity with longer maturities (Problem 5 - inadequate maturities). This option is also able to address problem 7 (underselling of capacities), as it does not involve any capacity allocation.

Option 6 contributes very positively to all objectives, except Objective 1.ii where its impact in small bidding zone may be limited due to structural lack of supply and demand, which can only be solved by integrating it with other bidding zones.

ACER and CEER therefore consider that this option is suitable for a targeted intervention in specific cases as a supplement to forward markets, but it is not preferred as a European solution for addressing the problems related to electricity forward market.

In summary, ACER and CEER consider that at this stage Options 3, 4 and 5, all of them combined with Option 1, are the preferred policy options, whereas Options 0, 2 and 6 are not proposed to be pursued at the European level. Option 6 may still be preferred in specific cases, where regulatory authorities decide at regional level that no intervention is needed at regional level, but only in one or few bidding zones. Table 1 summarises the analysis of all the options on the type of TSO intervention.

Table 1: Summary of the options on the type of TSO intervention[11]

	Option 0	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6
Problem 1	0	0	+	++	++	++	+
Problem 2	0	0	0	++	++	++	++
Problem 3	0	+	-	+	++	++	++
Problem 4	0	0	0	++	++	+	0
Problem 5	/	++	/	/	/	/	++
Problem 7	0	0	+	+	++	++	++
Objective 1.i	+	0	+	++	++	++	++
Objective 1.ii	0	0	+	++	++	++	+
Objective 1.iii	0	++	-	/	/	/	++
Objective 2.i	0	0	0	++	++	++	++
Objective 2.ii	0	+	+	+	++	++	++

- means partly negative, 0 means neutral, + means partly positive, ++ means positive, "/" means independent from

7.1.3 Type of products offered by the TSO

Three options were identified in this category (section 6.4): Status Quo with PTRs and FTR options, PTRs/FTRs with reduced firmness and FTR obligations.

First, ACER and CEER are of the opinion that PTRs/FTRs with reduced firmness is the least desirable option because it significantly undermines the very objective of hedging products, which is to provide a hedge against the underlying risk, which includes the risk of decoupling. If regulatory authorities conclude that the forward market needs regulatory support it would be counterproductive that such support is in the form of products that do not provide efficient hedging opportunity (i.e. 100% hedge). Such a position would contradict the very essence of the underlying conclusion that the forward market needs regulatory support

Regarding the comparison of Option 0 and Option 2, ACER and CEER understand that Option 0 may be preferred by many market participants in the current design where PTRs and FTR options are offered on bidding zone borders. However, Option 0 does not address Problem 6 (inefficient products), whereas Option 2 does. In addition, Option 3 in the second category (type of TSO intervention) can only work with FTR obligations. In addition, the academic literature outlined in Chapter 4, indicate superiority of FTRs over PTRs, the latter negatively affecting seller and buyer market power. Given that Option 3 is among the preferred policy options for the future forward market design, ACER and CEER prefer FTR obligations in order

[11] Problems 6 and 8 are not included in the table as they are addressed respectively by the type of products offered by the TSO and the need for intervention.

to support Option 3, because Option 3 cannot work with FTR options. Options 4 and 5 are independent of this choice as they by default involve products which are obligations.

8. RECOMMENDATIONS AND PROPOSED ACTIONS

As a preliminary conclusion ACER and CEER identify that existing electricity forward markets in the EU suffer from a number of problems which prevent achieving the objective of an effective and efficient electricity forward market. The main shortcoming of existing forward markets is that they do not function as a single integrated forward market. This objective was achieved in the day-ahead and intraday timeframe (soon also in the balancing timeframe) with the help of (implicit) cross-zonal capacity allocation. However, in the forward timeframe, the long-term capacity allocation is not designed in a way that would integrate national forward markets in the most efficient way.

In order to address these problems and achieve the objectives, ACER and CEER propose several improvements to the electricity forward market. Most of these improvements relate to better allocation of long-term cross-zonal capacities in a way that integrates national forward markets into a more integrated EU forward market.

First, ACER and CEER propose to harmonise the assessment and decisions by regulatory authorities by which the need for regulatory intervention in the electricity forward market is identified and a decision on an intervention is made.

Once the decision on the intervention is made, ACER and CEER identify three promising policy options for the type of regulatory intervention aiming to address the identified problems with better allocation of long-term cross-zonal capacities. These are allocation of zone-to-hub FTRs by TSOs, market coupling with CfDs and market coupling with energy futures. All three options involve allocation of long-term cross-zonal capacities by TSOs (either explicit or implicit) in timeframes up to three years ahead of delivery. At this stage a more detailed analysis and discussion are needed on the selection of these three options, namely their true potential to improve the forward market functioning as well as the implementation and operation efforts and costs compared to the benefit they would bring.

In case TSOs allocate long term transmission rights, ACER and CEER also recommend that these are allocated in a form of FTR obligations and not FTR options or PTRs. In case of options based on market coupling the underlying products are by default obligations.

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ANNEX I – FINANCIAL TRANSMISSION RIGHTS IN NODAL MARKETS – THEORY AND PRACTICE

FTRs have been originally proposed by Hogan (1992) and successfully implemented, with slightly different features, in all liberalized markets based on Locational Marginal Pricing (LMP), including the United States.

In general and similarly to the definition of FTRs in the European market design, FTRs hedge the buyer against the market price difference between two or more price zones and they have no impact whatsoever on the economic dispatch or on the actual use of the transmission network according to Hogan (1992) and Battle et al. (2014).

Financial transmission rights (obligations or options) can be designed as point to point FTRs or as Flow Gate Rights (FGRs) that are directional rights defined over specific time intervals and specific links, entitling their holder to the shadow price on the link's capacity constraint in the designated direction per MW denomination. However, as assessed by Oren (2013) FGRs are rarely used in the markets nowadays since energy traders prefer FTRs that are more suitable for hedging point to point congestion risk. To compare those products to the different FTR products studied throughout this document for the European market design, FGRs show similar characteristics than the currently implemented bidding-zone-border FTRs. Point to point FTRs can be compared with zone-to-zone FTRs in a zonal market.

A central feature is the concept of revenue adequacy of FTRs to provide full funding and the associated transmission hedges that link transactions between different locations. Hogan (1992) shows that if the outstanding FTRs satisfy a "simultaneous feasibility test" and the network topology is fixed then the FTR market is "revenue adequate". Revenue adequacy means that congestion revenues and merchandising surplus (i.e., the difference between the buying cost and the sales revenues for energy traded through the pool) collected by the system operator from bilateral transactions and local sales and purchases at the LMPs, will cover the FTR settlements. The principle of revenue adequacy is also central in the transmission rights in the EU.

It is acknowledged that FTRs were developed primarily to replace physical firm transmission rights in markets based on economic dispatch and LMP, thereby enabling load serving entities (i.e. utilities that have a service obligation) and generators to continue entering long term contracts. This is the crucial role remarked by many authors and system operators such as Hogan (2018) and PJM (2020). As proposed in the section 7.1.3 of this document, FTRs could also replace PTRs in Europe.

All liberalized markets in US and other markets based on LMP implemented hedging instruments that despite the different names refer to the FTRs instrument, as shown in Table 2 below:

Table 2: Nodal-based market experience with FTRs (overview)

Market	Financial transmission right	Auction revenue right
ISO NE (US)	FTR	ARR
NYISO (US)	Transmission Congestion Contract (TCC)	-
PJM (US)	FTR	ARR

MISO (US)	FTR	ARR
ERCOT (US)	Congestion revenue rights (CRR)	-
CAISO (US)	Congestion revenue rights (CRR)	
Southwest power pool (US)	Transmission congestion right (TCR)	ARR
Singapore	FTR	
New Zealand	FTR	

In general FTRs are issued by the Independent System Operator (ISO) through an auction and a priority allocation to load serving entities and project sponsors of transmission facilities may occur (Alderete (2016), House (2020), PJM (2017)).

An **Auction Revenue Right** is a Market Participant's entitlement to a share of revenue generated in annual FTR auctions. A Market Participant's firm historical usage of the ISO's transmission system determines its share and, depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge. ARR can be also converted into FTR, by scheduling this product in the FTR auction. This specific product is not present in the European market design nor in other non-US markets due to the different approaches followed regarding the historical usages of transmission systems.

In ISO markets where ARR are used, the allocation of rights to load serving entities and transmission sponsors is done through this sort of products which are auctioned up to multiple years prior to the delivery. Market participants may decide to: i) get the revenue stream from the FTR auction, ii) convert the ARR into FTR and iii) sell ARR into secondary market (see for example PJM (2017).

FTRs can be traded by any party, no matter if it is a participant that bids in the electricity market. This improves liquidity of the FTR market.

No cost allocation or priority allocation of FTRs to load serving entities demonstrates the aim of redistributing congestion costs and protecting loads against congestion risks.

Long term contracts are usually a significant component of the electricity markets; the share of bilateral and self-supply contracts can be very high, as in the case of PJM (see **Error! Reference source not found.** below from PJM (2020). In general, bilateral and self-supply contracts (with physical delivery) are notified to the pool run by the ISO and subject to the payment of congestion charges. In this last respect, the FTR market is an essential tool to ensure hedging.

Table 3: Method for supplying load in PJM day-ahead market (PJM 2020)

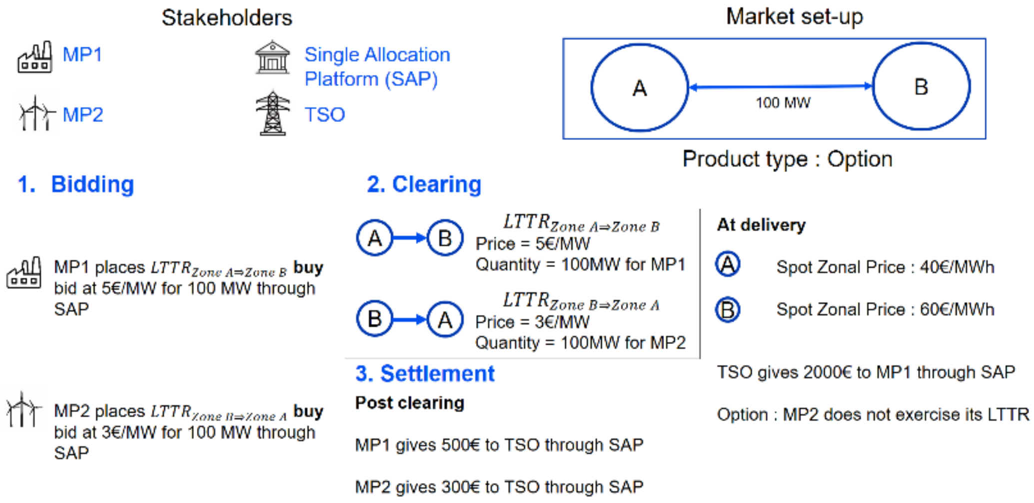
2008 - 2018	Spot Market	Self-supply and bilateral
Average	24.2%	75.8%

ANNEX II – EXAMPLES OF TSO/MARKET ARRANGEMENTS

This Annex presents concrete cases of policy options discussed in the main document. In all cases the values and units are normalised to one hour.

Case 1: Bidding Zone Border Long-Term Transmission Rights (BZB LTTRs)

In this type of arrangement, the TSOs and the Single Allocation Platform are involved. TSOs allocate long-term cross-zonal capacities and issue LTTRs (financial or physical) to market participants. Those LTTRs allow the market participants to hedge the price difference between two neighbouring zones (in a specific direction in case of PTRs or FTR options).



The above example is valid for the currently allocated FTR options or PTRs (FTR obligations are not considered here) where the market participants can hedge different borders and directions. The auction price and quantity is defined by a welfare optimization of the bids of the market participants and the volume of cross-zonal capacities offered by TSOs. In the settlement phase, there are two steps at which financial flows take place. First, following the LTTR auction, the market participant will pay to the TSO through the SAP the following amount:

$$Amount\ to\ pay = \ LTTR\ Volume * \ Auction\ Price\ of\ LTTR$$

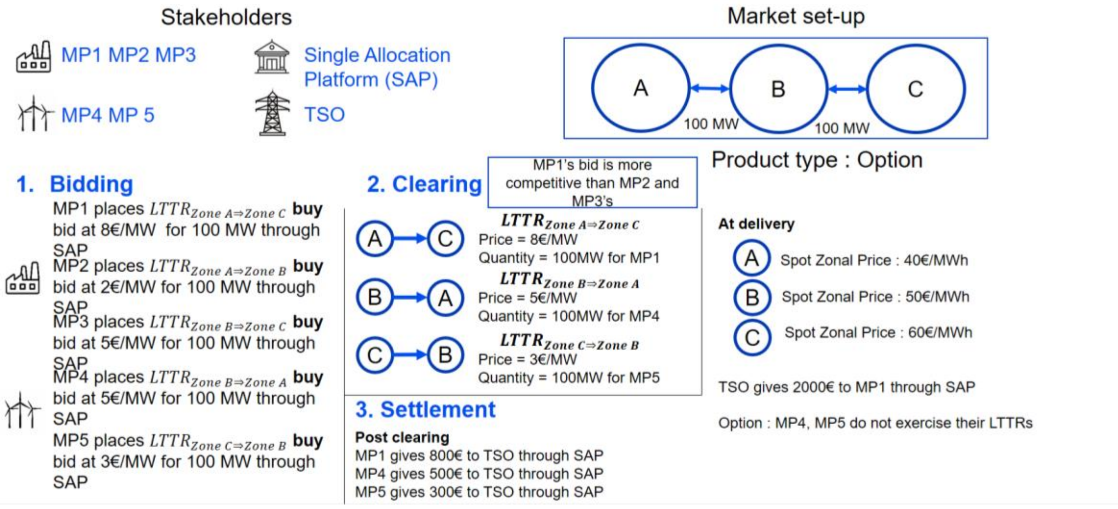
After delivery, the market participants (except those which choose to nominate PTRs) will receive from the TSO through the SAP the following remuneration (in case of obligations also the negative market spread is taken into account):

$$\begin{aligned} &Amount\ to\ receive \\ &\quad = LTTR\ Volume_{Zone\ A \Rightarrow Zone\ B} \\ &\quad * \max\left(0, Zonal\ Spot\ Price\ B - Zonal\ Spot\ Price\ A\right) \end{aligned}$$

This market arrangement is currently applied in continental Europe.

Case 2: Zone-to-Zone Long Term Transmission Rights (Z2Z LTTRs)

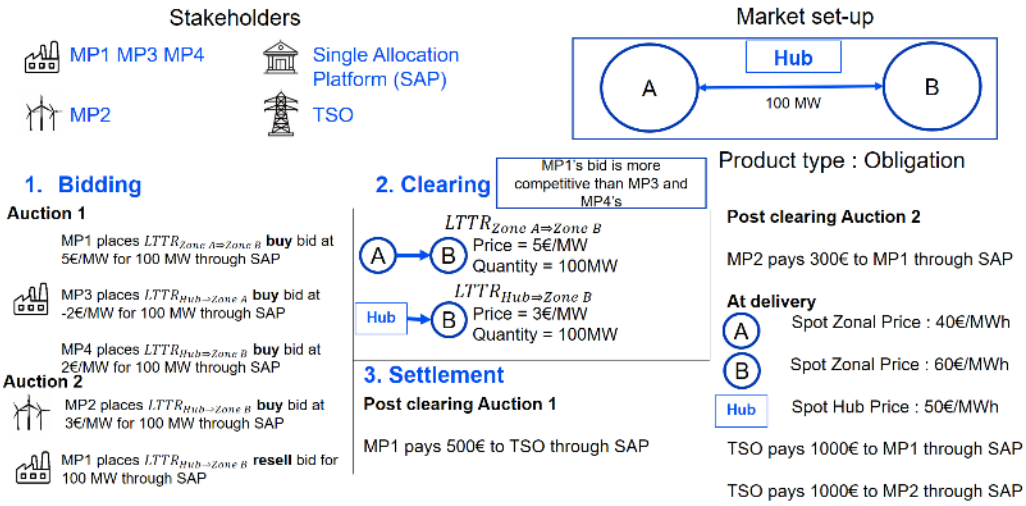
This type of arrangement is similar to LTTRs, but also adds the possibility to place LTTRs bids from a zone to another non-neighbouring zone. Based on a welfare optimization, competitive bids will be assessed in order to maximize the welfare of the auction.



The above example is illustrating a case with FTR options where a Z2Z bid (MP1) from Zone A to Zone C competes for cross-zonal capacity with the combination of two Z2Z bids (Zone A to B from MP2 and Zone B to C from MP3). As The first Z2Z bid (MP1) is more competitive (higher price) than the combination of the two Z2Z bids, it is cleared and the two Z2Z bids are not.

Case 3: Zone-to-Hub Long-Term Transmission Rights (Z2H LTTRs)

This type of arrangement is similar to Z2Z LTTRs but also adds the possibility to place bids from a zone to a hub. Based on a welfare optimization, competitive bids will be assessed in order to maximize the welfare of the auction. This option differs depending on the options or obligations. For simplicity only the case of FTR obligations is shown in the example.



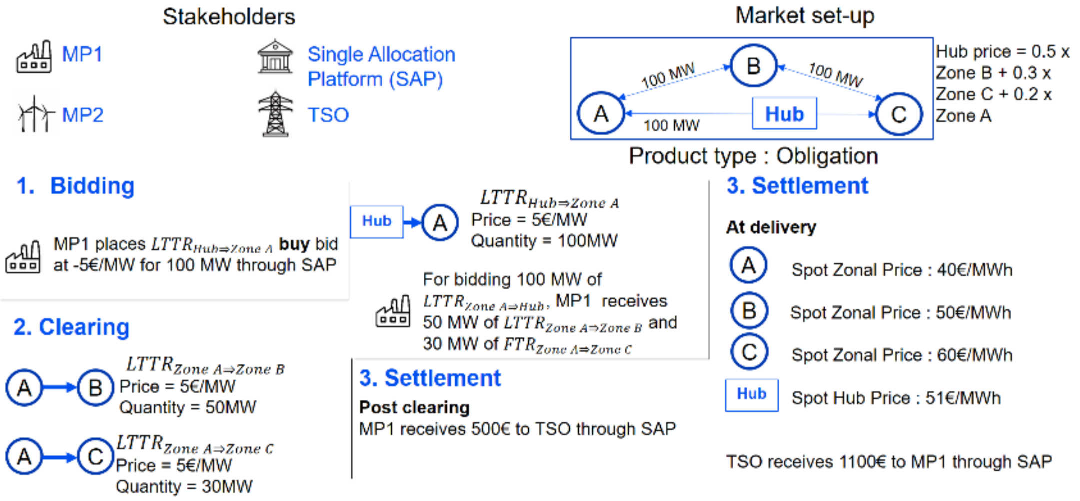
In the above example, a Z2Z bid (MP1) from zone A to zone B competes for cross-zonal capacity with the combination of two Z2H bids (zone A to hub from MP3 and zone B to hub from MP4). As the Z2Z bid is more competitive (higher price) than the combination of two Z2H bids, it is cleared and the two Z2H bids are not.

Also, the above example presents the situation in which a MP (MP1) places a resell bid of the previously acquired LTTR product through the SAP. This resell bid can be a price taking bid (shown in example) or specific price bid indicating that LTTR will be resold only if auction price is equal or higher than bid price.

Case 4: Variant Zone-to-Hub Long-Term Transmission Rights (Variant Z2H LTTRs)

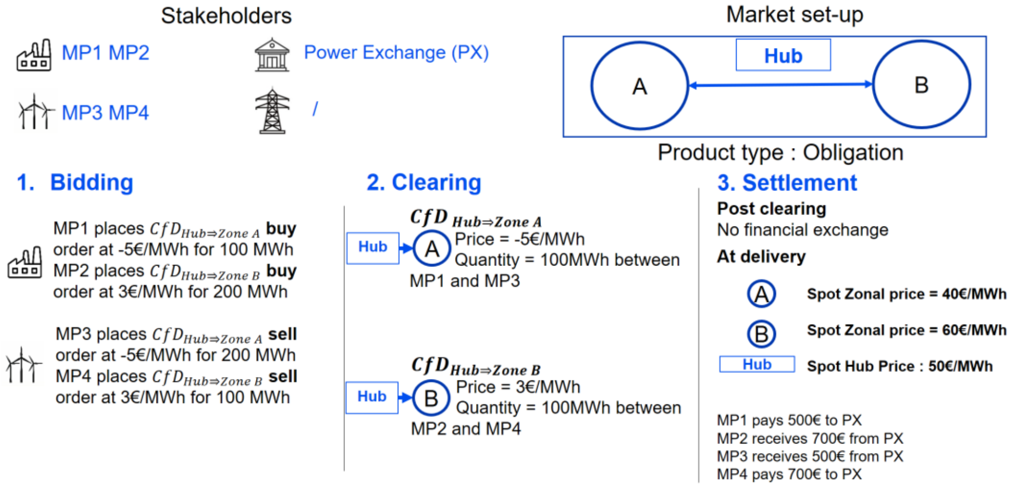
This type of TSO arrangement provides an alternative to Z2H LTTRs. The difference between this set-up and the Z2H LTTRs is the following:

In this arrangement, a hub price calculation will be defined prior to the LTTR market opening by applying “weights” to different zones. Those weights could be defined based on the traded volumes of the last year prior to the auction. When placing a LTTR Z2H bid, the market participant will receive a sum of multiple Z2Z LTTRs based on the same “weights” than the one used for the hub price calculation.



Case 5: Contract for differences (CfDs) without coupling

In this type of arrangement, TSOs are not involved. A PX offers trading with CfDs to market participants. Those CfDs allow the market participants to hedge the price difference between a zone and a hub.



In the above example, the supply and demand of CfDs in zones A and B is perfectly matched – there is no cross-zonal matching. In the settlement after delivery, the market participants will have the following financial flow through the PX (negative value indicate pay for buy orders):

$$\begin{aligned} &Amount\ to\ pay/receive \\ &\quad = CfD\ Volume * ((Zonal\ Spot\ Price - Hub\ Spot\ Price) \\ &\quad - Matched\ CfD\ Price)\ [€/MWh] \end{aligned}$$

This market arrangement is currently applied in the Nordic region.

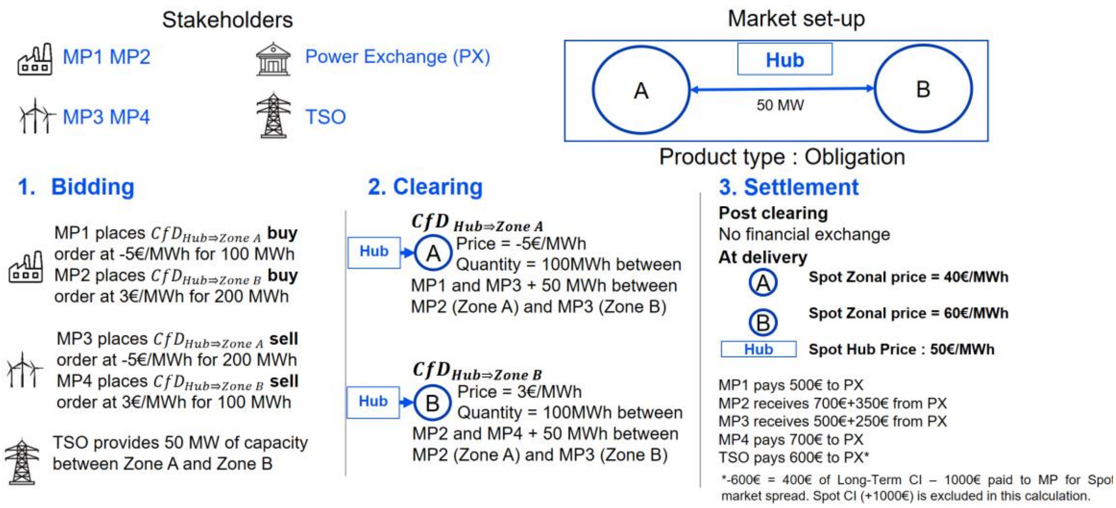
Case 6: Forward Market Coupling with Contracts for Difference (CfD Coupling)

This arrangement involves both TSO and PXs (NEMOs). In this set-up, the power exchanges offer trading with CfDs allowing for a hedge between a hub spot price and a zonal spot price. The TSO will offer capacity between the zones. Through a welfare optimization, the clearing will select the sell and buy orders while respecting the constraint of the cross-zonal capacity. Financial flows of the market participants are computed and settled in a similar way than in Case 5 with CfDs, namely market participants have to pay the matched price and receive the difference between zonal spot price and hub price (negative value indicate pay for buy orders):

$$\begin{aligned} &Amount\ to\ pay/receive \\ &\quad = CfD\ Volume \\ &\quad * \big((Zonal\ Spot\ Price - Hub\ Spot\ Price) - Matched\ CfD\ Price)\big) \end{aligned}$$

The congestion income of the TSOs is computed as a difference between congestion income TSOs receive in the long-term timeframe when matching and coupling the CfDs and remuneration costs TSOs have to pay from the day-ahead congestion income (equivalent to LTTR remuneration) (negative value indicate negative income):

$$\begin{aligned} &Congestion\ income_{\ Zone\ A \Rightarrow Zone\ B} \\ &\quad = Interconnection\ capacity \\ &\quad * \big((Matched\ CfD\ Price_{Zone\ B \Rightarrow Hub} - Matched\ CfD\ Price_{Zone\ A \Rightarrow Hub}) \\ &\quad - (Zonal\ Spot\ Price\ B - Zonal\ Spot\ Price\ A)\big) \end{aligned}$$



In the above example, the TSO receives as long-term congestion income resulting from forward market coupling the difference in clearing price of the CfDs in both zones multiplied by the provided capacity ($50 * (3-(-5) = 400€$) and at the delivery has to remunerate the difference in clearing price of the two zones multiplied by the provided capacity ($50 * (60 - 40) = 1000€$) to PXs and MPs due to the reallocation of long-term cross-zonal capacity. The TSO therefore has a negative net congestion income because the long-term market spread was lower than the day-ahead market spread.

Case 7: Forward Market Coupling with Futures

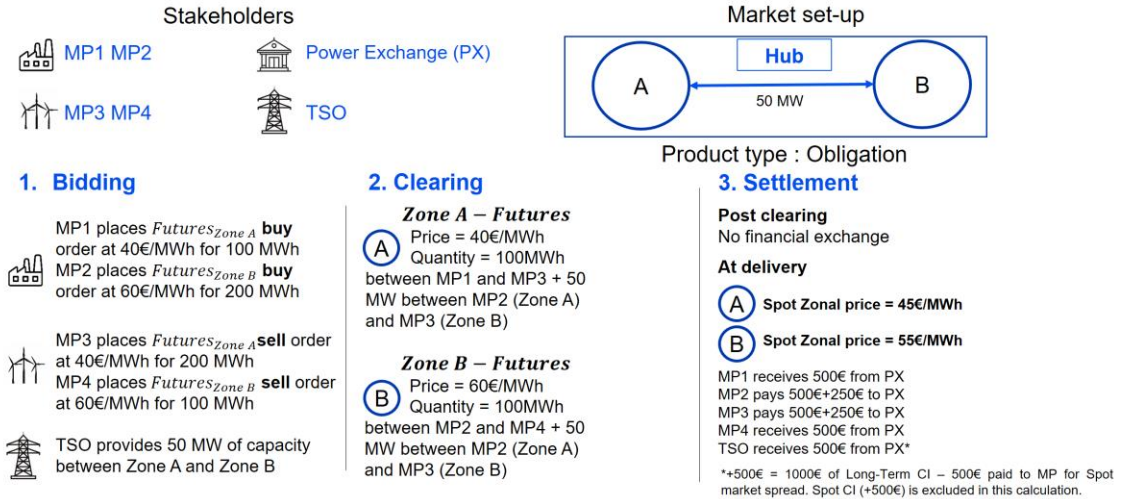
This arrangement involves both TSOs and PXs (NEMOs). In this set-up, the NEMO offers trading energy futures that can be matched across the border with a transmission capacity offered by the TSO. The bids of the market participants will be selected in order to maximize the social welfare of the auction while respecting the cross-zonal capacities provided by the TSO.

Financial flows of the market participants are computed as a difference between the obligation arising from matched futures prices and obligations arising at delivery i.e. zonal spot prices (negative value indicate pay for buy orders):

$$Amount\ to\ pay/receive = Futures\ Volume\ * (Zonal\ Spot\ Price - Matched\ Futures\ Price)$$

The congestion income of the TSOs is computed as a difference between congestion income TSOs receive in the long-term timeframe when matching and coupling the Futures and remuneration costs TSOs have to pay from the day-ahead congestion income (equivalent to LTTR remuneration) (negative value indicate negative income):

$$\begin{aligned} Congestion\ income_{\ Zone\ A \Rightarrow Zone\ B} &= Interconnection\ capacity \\ &* \big((Matched\ Futures\ Price_{Zone\ B} - Matched\ Futures\ Price_{Zone\ A}) \\ &- (Spot\ Price\ Zone\ B - Spot\ Price\ Zone\ \ A)\big) \end{aligned}$$



In the above example, the TSO receives as long-term congestion income resulting from forward market coupling the difference in clearing price of the zonal futures in both zones multiplied by the provided capacity ($50 * (60 - 40) = 1000€$) and at the delivery has to remunerate the difference in spot clearing price of the two zones multiplied by the provided capacity ($50 * (55 - 45) = 500€$) to PXs and MPs due to the reallocation of long-term cross-zonal capacity. The TSO therefore has a positive net congestion income because the long-term market spread was higher than the day-ahead market spread.