

ENTSO-E consultation on its discussion paper “Options for the design of European Electricity Markets in 2030”



EFET response – 14 May 2021

The European Federation of Energy Traders (EFET) welcomes the opportunity to provide comments on the ENTSO-E discussion paper “Options for the design of European Electricity Markets in 2030”.

While we support ENTSO-E’s decision to seek views from market participants before finalising its recommendations, we are unconvinced that these topics should be the priority at this point in time. We therefore encourage TSOs and ENTSO-E to focus on the significant amounts of important work which is still required to meet the requirements of existing legislation, including the Third Energy Package and Clean Energy Package, and to deliver the Target Model. There is much still to be done to develop the full suite of network codes and guidelines and to ensure customers across Europe benefit from a well-functioning Internal Energy Market (IEM).

Once fully implemented in all parts of Europe, we believe that the Target model will deliver positive outcomes for security of supply, competition, and decarbonisation:

- *Security of supply* – The price signals sent through the various markets which make up the IEM will ensure that power flows to where it is most needed and that we make the best use of generation capacities.
- *Competition* – Efficient markets in all timeframes and robust capacity calculation processes will create further competitive pressures which will serve to reduce customer bills.
- *Decarbonisation* – The IEM will also facilitate the integration of much greater volumes of renewable energy, provide signals about where flexible capacity is required, allow efficient decisions between technologies to be made and create strong incentives for further innovation – which will be vital in Europe becoming carbon neutral.

We would like to see ENTSO-E’s work focussing in the following areas:

1. *Embracing TSO’s role as neutral facilitators of markets* –
 - a. TSOs have an important role to play in facilitating the development of markets. But their role must remain neutral and the principle of unbundling should remain a fundamental cornerstone of the European model.
 - b. TSOs need to work more closely with their DSO colleagues, recognising that the European system is exactly that – a single system as opposed to a ‘system of systems’.
 - c. And there may be a case to consider the longer term governance issues related to system operation.
2. *Enhancing competition within markets* –

The European Federation of Energy Traders (EFET) promotes and facilitates European energy trading in open, transparent and liquid wholesale markets, unhindered by national borders or other undue obstacles. We build trust in power and gas markets across Europe, so that they may underpin a sustainable and secure energy supply and enable the transition to a carbon neutral economy. EFET currently represents more than 100 energy trading companies, active in over 27 European countries. For more information: www.efet.org

- a. We urge TSOs to recognise the importance of price signals which reflect underlying economic conditions in allowing efficient decisions, including in the context of greater sector coupling, and to remove artificial barriers which limit prices.
- b. We also urge TSOs to be as transparent as possible about the methods used to calculate, and to maximise, cross border capacity.
- c. To the extent they're able, TSOs need to work to ensure that all technologies face the same set of appropriate and non-discriminatory market rules. These rules should ensure all producers and consumers face incentives to respond to the price signals sent by the market.

Ultimately the TSOs actions need to be guided by a prioritisation based solely on the scope to unlock social welfare benefits. With this in mind, you will find below our detailed answers to the consultation questions:

Wholesale markets

1. How could European Day-Ahead and Intraday markets be improved to further facilitate market access of RES and Distributed Energy Resources in 2030?

Well-functioning markets, in all timeframes, can underpin the development of renewable electricity generation (RES-E) and distributed energy resources as well as facilitate their cost-effective integration into the electricity system. A continuing focus on improving the operation of European electricity markets will benefit the uptake of renewables.

Efficient intraday markets will likely be the key enabler to the development of RES-E, distributed energy technologies and services such as demand-response and storage, which are particularly suited to absorb the effects of RES-E generation intermittency. Safeguarding and improving the efficiency of continuous trading would therefore contribute to the development of RES-E and to lowering balancing risks.

The presence of high shares of variable RES and distributed energy resources increases the uncertainty in the prediction of market conditions and network constraints. Therefore, improvements in access to continuous cross-border intraday trading such as coupling products with small granularity (i.e. 15-minute products), a harmonised imbalance settlement period to 15 minutes across Europe and setting the intraday gate closure time (including across border) 5 minutes before the start of the relevant market time unit (and ideally, even closer to delivery) would facilitate the valuation of RES-E output close to real time and optimise self-balancing.

Further key recommendations for the intraday market to facilitate market access of RES-E and distributed energy resources in 2030 are¹:

- Ensuring the effective harmonisation of cross-zonal intraday gate opening time (ID CZ GOT) and opening of shared order books at 15:00 (CET).
- Implementing clear, transparent and harmonised capacity calculation and recalculation methodologies and frequency.

¹ See also EFET position paper [Towards an efficient intraday market design in electricity](#)

- Ensuring that the harmonised technical price limit in ID includes an adjustment mechanism and reflects the value of lost load (VoLL).
- Doing away with local limitations to intraday trading, such as open position limits applicable before gate closure time.
- Ensuring minimum interruption time of the three pan-European auctions required by ACER decision by postponing their implementation until 15-minute products are available.

2. Are there any best practices which could be used as an example?

The XBID project, as part of Single Intraday Coupling Project (SIDC), could be seen as an example that creates a single EU cross-zonal intraday electricity market. This led market participants to work together across Europe to trade electricity continuously on the day the energy is needed, thereby promoting competition and increasing liquidity close to delivery.

This allows continuous cross-border trading opportunity close to real-time across Europe on one platform that enables increased optimisation of generation assets, especially RES-E.

3. What do you consider to be the main barriers for the participation of RES in balancing markets?

While the new Electricity Regulation 2019/943 and Renewables Directive 2018/2001 foresee the end of feed-in tariffs, balancing responsibility for all and the phase out of priority dispatch, these privileges are grandfathered for existing assets (and maintained for small installations in the future and proofs of concept in innovative technologies). The move towards a true level-playing field and contribution of all RES-E capacities to price formation in all timeframes will only be gradual.

RES-E installations that are operated under support schemes have fewer incentives to participate in balancing markets. Once the end of the financial support has been reached, RES-E participation in balancing will be required/important for RES-E operators. Full participation of all RES-E in all wholesale electricity markets and balancing mechanisms is vital to offer multiple revenues streams to RES-E operators. This will reduce the necessity for financial support schemes while price signal lower the cost of the energy transition for society.

Full participation of RES-E installations in balancing mechanisms also necessitates that all TSOs consider them as trustworthy contributors to system security, and not “something to manage”. Renewable generation can be a valuable contributor to system security, hence RES-E operators should be able to participate to all types of procurement for balancing capacity and energy. In particular, pre-qualification requirements and related procedures designed at national level should not distort the playing field for RES-E operators to participate directly or via aggregation in EU balancing markets. We see the way forward in their harmonisation at EU level.

Sometimes a discount factor is applied to renewable installations for their participation in balancing (and capacity) market mechanisms. With the further improvement of forecasting and controllable installations, together with pooling of resources in portfolios, these discount factors should be reviewed to better reflect the observable reliability of the service provided.

4. Which kind of support scheme has the least distortive effect on the participation of RES in balancing markets?

In the medium term, support schemes for RES-E should be removed for technologies reaching market parity (nascent technologies should be supported via R&D funding).

In addition to the valuation of RES-E in the wholesale electricity market and balancing mechanisms, RES-E technologies can be marketed to consumers via guarantees of origin (GoOs) or power purchase agreements (PPAs). Public financial support may continue to be needed for some time to attain targets, though it should not replace – nor exclude – the possibility for RES-E producers to value their electricity in the wholesale electricity market and balancing mechanisms.

5. What do you consider as best practice to the ensure effective provision of voltage control and other non-frequency Ancillary Services (AS) by RES?

Market-based procurement and competitive allocation should always be followed in order to reach cost efficiency. TSOs/DSOs need to specify their needs and procure these services through transparent, non-discriminatory and competitive processes, using standardised products. Before even thinking of investing in such capacity, TSOs/DSOs should always seek to procure those services from the market. Also, pooling of aggregated decentralised assets should be foreseen.

6. How could market design mitigate the side effects of the interaction of negative prices and RES supported technologies?

As a start, we remind ENTSO-E that there is nothing intrinsically wrong with negative prices – just as well as with price spikes – if they are induced by the natural forces of matching supply and demand. Negative prices simply evidence a surplus of electricity supply on the market. With the increasing build-out of RES-E technologies, the periods of potential negative prices will likely increase, at least in frequency. They will provide a useful signal for all market participants both on the supply and the demand side to adapt feed-in and off-takes.

However, negative prices can be induced – or exacerbated – by regulatory measures outside the control of market forces. This is notably the case when the payment of a premium for RES-E production is maintained even in case of negative prices. As long as there is financial support based on MWh produced without appropriate rules to halt support when prices go below 0, there is a risk of RES-E installations continuing to produce when prices are negative, exacerbating and possibly prolonging the negative price periods.

Ensuring that RES-E generators are not paid a premium in times of negative prices is necessary to avoid wrong incentives to RES-E generators, and to promote investment in and market participation of DSR and storage / flexible capacity. This will also facilitate carrying over dispatch and investment signals beyond the electricity market in view of sector coupling, thus bringing all energy carriers to contribute to the energy transition.

Allowing more investments to go into new technologies and services that can easily adapt to price fluctuations (such as electricity storage or power-to-X solutions) will increase the overall ability of the energy system to integrate more volatile RES-E production and therefore also support the achievement of volume-based renewable targets. It also has the upside of reducing

the risks and capital costs for developers, and the overall RES capacity needed. The otherwise curtailed renewable energy would have to be re-financed anyways.

Capacity-based support schemes or “investment support” schemes could also be considered. But the ideal solution is a phase out of RES-E support facilitated by a strengthened ETS.

Finally, the market design for 2030 should not focus on mitigating side effects of other instruments and consider that subsidies should be phased out as soon as they are deemed not required to achieve the targets anymore.

7. What do you consider to be the key market design barriers limiting the uptake of DSR?

The goal of ensuring that those consumers who wish to participate directly in a market can do so is one we support and clearly an active demand side would be hugely beneficial to bringing the costs of energy for all consumers. Where regulatory or legislative barriers to the participation of consumers – directly or through intermediation – to electricity markets or balancing mechanisms exist, they should be removed in accordance with the EU Directive 2019/944. Note that these barriers can be outright exclusions as well as administrative or technical requirements that effectively restricts access to electricity markets and/or balancing mechanisms.

The primary driver for market participation of DSR is the electricity price. Consumers who may want to engage in and value the flexibility of their demand on the market will only be incentivised to do so if they see a financial benefit to it. Therefore we consider it vital that price caps and floors limiting volatility further than the boundaries set in EU legislation and ACER Decisions, should be removed immediately. Such impediments to the free formation of prices should have been removed by the 1st of January 2020 as stated in art.10 of EU Regulation 2019/943. Full implementation has to be accelerated in all Member States, and TSOs can play a role in this compliance exercise by requesting regulatory or legislative modifications in that sense.

Another key barrier is the uncertainty created an inconsistent implementation of the unbundling principle. Every time a TSO or DSO is given control of flexible assets, this undermines the business case of competitive operators – including consumers – to take part in the market. Instead, flexibility services should always be procured from the market.

Like in the case of RES-E, national pre-qualification requirements to participate in balancing mechanisms or ancillary services tendres should not pose an undue burden on DSR, and should be ultimately be harmonised across the EU.

Where capacity mechanisms are being put in place, DSR should be able to bid into them on the same basis as generation capacity. Consequently, the rules for DSR and generation capacity should be the same wherever possible.

8. What do you consider to be the best practices for the facilitation of demand side response?

Currently, most users connected to the transmission grid have access to the energy-only market. In our view, a fundamental requirement for market access is balance responsibility.

This gives a right to access the market and to trade with any other market participant, with the accompanying requirement to submit schedules and settle imbalances. This applies to generation, storage and demand response.

A specific challenge regarding balance responsibility is for demand-side response for retail consumers. This will be gradually covered with the roll-out of smart meters. As soon as settlement and reconciliation processes are adapted for 15-minute metering for domestic consumers, suppliers can offer dynamic price contracts where consumers can respond accordingly (implicit demand response). This is already the case in some EU countries that have rolled out smart meters but may have longer timeframes. Note that implicit demand already exists since many years but was limited to less dynamic retail prices for household consumers (e.g. static Time of Use contracts) or for consumers above certain voltage levels (commercial and industrial) which tend to have more sophisticated meters already.

Explicit demand side response should also be allowed. This means that a consumer is offering its flexible capacity to the wholesale market directly or through an independent aggregator, while at the same time its residual demand is supplied by a supplier. In principle, the contractual agreements between consumer, supplier and aggregator can remain freely negotiated. At the same time, it is possible to develop standard procedures (e.g. to define a baseline consumption) in order to facilitate this business model. However, prices and other commercial terms must remain unregulated.

Besides power generation, the contribution of demand side response in the delivery of balancing capacity and energy (FCR, FRR and RR) must be possible, as well as in non-frequency ancillary services. This requires that TSOs and DSOs accept offers where market participants aggregate different capacities into a pool.

Ultimately, the choice to participate actively in the market should remain that of consumers themselves. Many may not wish to do so and will want to feel they are getting a fair price and that they can trust the company(ies) supplying them (and the system overall). For them, retail suppliers will continue to carry the market risk and offer fixed-price contracts, but NRAs should not relinquish efforts to phase out regulated retail tariffs – save to preserve selected consumers from energy poverty. Offering a wide range of choices to consumers was, in many ways, the rationale for introducing market competition in the first place and we think that logic holds today.

9. Do you see benefits in increasing the number of intraday auctions?

No, as explained in detail in our EFET position paper [Towards an efficient intraday market design in electricity](#). The debate regarding the design of intraday markets at the EU level revolves around continuous trading versus auctions. EFET has been a strong supporter of continuous cross-border intraday trading for years. While both designs come with advantages and drawbacks, we consider continuous trading a better option, in particular as it improves the reaction capacity of market participants close to real time, which is essential for the integration of RES into the market and the development of innovative technologies and services such as demand response and storage. The introduction of regional or pan-European auctions, on the other hand, would drain liquidity from continuous trading, thereby reducing severely its efficiency.

Continuous cross-border intraday trading allows for better and faster trading opportunities compared to auctions. It is perfectly suited to deliver an almost real-time price signal and allows market participants to optimise continuously the dispatch of their production and consumption close to real time, as market and physical conditions evolve. It is worth noting that the last hour before delivery is the most vital for market participants and is where most trades on continuous ID markets take place. The design of existing or planned intraday auctions (pan-European or regional) do not allow trading that close to real time.

The recent experience following the launch and extension of XBID shows a surge in intraday transactions in bidding zones and at borders where continuous trading was previously not available, showing market participants' appreciation of its capacities. For RES-E producers in particular, continuous trading is more advantageous, as it offers an instantaneous possibility for market participants to trade, allowing them to adjust their position continuously, according to production forecast updates (without having to wait until the next auction). The evolution towards shorter granularity products, including across borders, is making continuous cross-border trading even better suited for RES generation.

Technologies and services such as demand-response and storage, which can be particularly well-suited to absorb the effects of RES generation intermittency, also benefit from continuous trading and shorter granularity products. Safeguarding and improving the efficiency of continuous trading would contribute to the development of these activities.

The market vs. security dichotomy, where continuous trading represents "more market" and auctions mean "more security," is sometimes put forward. This debate, however, is misleading. Allowing market participants to use cross-border capacity very close to real time to adjust their positions close to delivery (self-balancing), combined with adequate TSO transparency on system state, is the best means to ensure system security. This reduces the need for residual balancing by TSOs and thus, improves system security.

One of the criticisms of the continuous trading system is that the first-come first-served allocation of transmission capacity inherent to it does not allow for congestion-based pricing of transmission capacity. As a result, dispatch distortions are created in the short term, and investment distortions in the long term. We do not agree with this line of thinking. Fundamentally, pricing scarce intraday cross-zonal capacity is about redistribution of benefits from market participants to TSOs, rather than about increasing social welfare. All things equal, it is primarily a question between the benefits of first-come-first-served capacity for market participants – with an ultimate redistribution to end consumers via lower energy costs in their bill – and the benefits of reduced congestion for TSOs – with an ultimate redistribution to end-consumers via lower transmission costs in their bill. Besides, pricing intraday capacity, if it has not been recalculated after day-ahead clearing, would be tantamount to pricing it twice, as left-over capacities from day-ahead were valued at zero at that point in time.

10. If so, what would be an adequate number of auctions per day?

Ideally, none. Intraday auctions should not be implemented in parallel to continuous trading, as their harmful impact on the liquidity of the continuous market would outweigh considerably the advantages suggested by their proponents. Auctions only make sense if they are used to allocate additional amounts of cross-zonal capacity. We nonetheless take note of ACER's Decision to introduce three pan-European auctions to complement continuous trading. This

Decision came as a disappointment following the much more reasonable proposal of all TSOs to hold a single pan-European auction before the gate opening of continuous trading.

However, we call for reducing the interruption time that the pan-European auctions would cause to continuous trading. It should be the goal of TSOs to reduce the interruption time of XBID induced by the pan-European auctions to 10 minutes maximum.

Should complementary regional auctions be introduced in certain regions, they should be accessible to all market participants without discrimination, i.e. irrespective of location or physical asset ownership. They should be designed from the start to ensure that each auction does not interrupt XBID for more than 10 minutes, as per Article 63.2 of the CACM Regulation.

11. Would you still see a role for cross-zonal intraday continuous trading if such adequate number of Intraday auctions would be implemented?

We absolutely do, as explained in our answers to questions 9 and 10.

12. What potential benefits or drawbacks do you foresee in combining day-ahead and intraday auctions?

So far, TSOs have made a convincing case neither for real welfare gains linked to the introduction of intraday capacity pricing itself, nor for a solution that would limit the negative effect of intraday capacity pricing auctions on the continuous market. Considering all this and the fact that intraday capacity pricing auctions will necessarily have a disruptive effect on the efficiency of continuous trading (XBID interruptions, liquidity drain), we see intraday auctions as risking to create welfare losses rather than gains.

13. Would you recommend any alternative solution which could achieve similar objectives?

Under the assumptions that EBGL, CACM GL and CEP are fully implemented by 2030, the following further enhancements can be considered:

- **Drawing a clear distinction between physical schedules and commercial transactions:** A number of jurisdictions maintain legal requirements for market participants to be balanced in DA. These requirements are a) impractical, as DA forecasts are increasingly unreliable due to the growing share of RES, and b) constitute a hindrance on portfolio optimisation and proprietary trading. Market participants must be free to optimise their full portfolio across all timeframes until the gate closure of the intraday market. Turning the obligation to be balanced in DA to a simple notification of physical schedules without concern for a market participant's commercial position in DA (regardless of whether the market participant is an asset owners or not) would both ensure that TSOs receive in a timely manner accurate information for planning purposes and remove a considerable restriction on free price formation.
- **Portfolio bidding across Europe:** The market model chosen in certain Member States continues to mandate market participants to bid separately for each unit in the intraday market or imposes portfolio optimisation restrictions, while market participants in most other bidding zones can optimise their portfolio without linking bids to specific

units and can net freely positions prior to trading. This “unit bidding” model either prevents market participants from deviating from schedules linked to individual transactions, or requires them to trade on the market every variation of schedules, rather than simply allowing the reallocation of production or demand within the same portfolio. Portfolio bidding allows for a more efficient optimisation of production and demand portfolios and is a necessary precondition for improving liquidity in the intraday market. We call for the introduction of this market model everywhere where unit bidding is still mandatory or portfolio use restrictions are in place.

- **Capacity calculation and recalculations in intraday:** The adoption of capacity calculation methodologies (CCM) for intraday according to the CACM GL requirements has been a lengthy process. At this stage, most regions have adopted their CCM, but how, how fast, and how frequently calculation and recalculations of cross-zonal capacities will be performed in intraday remains unclear. The ACER Decision of 21 February 2019 recommends that capacity calculation and recalculation for ID is carried out at least in accordance with the required auction schedule - first calculated by ID CZ GOT (i.e. 15:00 D-1), using the cross-zonal capacity remaining from the day-ahead timeframe, then at 22:00 D-1, and later at 10:00 on the delivery day. Paragraph (52) of the ACER Decision of 24 January 2019 on intraday capacity pricing appears to recommend these deadlines for intraday capacity (re)calculation for the whole SIDC area. We call on TSOs to implement these requirements.

When ID capacity (re)calculation is performed, TSOs should inform market participants of available volumes, as well as any use of ID capacities by TSOs themselves for countertrading or redispatch. Concretely, all the information on ID cross-border capacities available in the Capacity Management Module (CMM) should be shared transparently with all market participants.

- **Development of products with a 15-minute granularity (both in DA and ID) and harmonisation of the imbalance settlement period (ISP) to 15 minutes across Europe:** Full harmonisation should include 15-minute ISP, 15-minute cross-border granularity (gates) and 15-minute granularity of tradable products. Due attention should, of course, be given to the performance of the day-ahead and intraday coupling algorithms to ensure coupling operations remain at least at the same level of reliability as today. Cross-product matching should be available between the moment 15-minute products are introduced and that when all MTUs and ISPs are harmonised to 15 minutes.
- **Effective harmonisation of cross-zonal intraday gate opening time (ID CZ GOT) and sharing of order books:** Although ACER has set the cross-zonal intraday GOT to 15:00 (CET) D-1 for the whole of Europe, many TSOs in Continental Europe do not offer capacity until much later – e.g. up to 22:00. We request that at least the capacity left from the DA timeframe should effectively be made available to the market by all TSOs at the GOT of 15:00, if TSOs’ calculations allowing for new capacity to be offered have not been done yet.

In addition, to improve liquidity on the market, we request the sharing of order books by all NEMOs from the official CZ GOT set by ACER at 15:00, in line with the requirement that order

books should be shared for the whole duration of SIDC. Local technical or regulatory hurdles to order book sharing should be removed to ensure full compliance with the ACER Decision.

- **Cross-zonal intraday gate closure time (ID CZ GCT) set to 15 min (or even closer) before the start of the relevant market time unit and sharing of order books:** Cross-zonal intraday markets should be open closer to real time than they are today, and we see a cross-zonal gate closure 15 minutes before the start of the MTU as a way forward. In the long run, the ID CZ GCT should be set even closer to the start of a relevant market time unit (5 minutes).

For the sake of improving liquidity throughout the ID timeframe, including at local level, it is also important to extend the sharing of order books by NEMOs until local ID GCT. Where local ID GCT is already 15 or even 5 minutes before delivery, and as market design evolves in other places towards extending the ID market closer to real time, continued sharing of order books until local ID GCT would be particularly beneficial.

- **Technical price limits in intraday:** For single intraday coupling, ACER set a technical price limit of +/- 9,999 EUR/MWh in its Decision of 14 November 2017. The intraday technical price limits, however, do not foresee an automatic readjustment mechanism when prices come close to the limit, as is the case for day-ahead price limits. A review of the Decision is needed to ensure that the harmonised technical price limit in ID includes an adjustment mechanism and reflects the VoLL.

- **Keeping the negative impact of auctions on continuous trading to a minimum:**

We call for reducing the interruption time that the pan-European auctions would cause to continuous trading. It should be the goal of TSOs to reduce the interruption time of SIDC induced by the pan-European auctions to 10 minutes maximum.

Further, we oppose market design proposals that would increase the number of pan-European auctions beyond the three auctions foreseen in the ACER Decision, as that would have an even greater detrimental effect on the liquidity of the continuous market.

Complementary regional auctions that have been introduced in certain regions should be phased out.

14. How could markets for forward transmission capacity be improved to support the energy transition?

First, we believe that all TSOs should issue LTTRs at European bidding zone borders. Exceptions to this rule have proved to be dissatisfactory for market participants who repeatedly complain about the lack of hedging opportunity at bidding zone borders where no LTTRs are allocated (e.g. Nordics). Dismissals by TSOs and NRAs of such concerns, or the circumvention of articles 30.5 and 30.6 of the FCA GL requiring that alternative hedging instruments be developed in case of missing hedging opportunities, show that this exception needs to be abolished. TSOs sitting idly on the hedging option that forward transmission capacity represents is not only a loss for the market, it also represents missed congestion rent for TSOs.

We believe that the “block bids” approach to year-ahead long-term transmission rights (LTTRs) allocation, whereby all the capacity calculated by the TSOs the year before delivery is allocated to market participants in the year-ahead auction via monthly LTTRs would be an important market design evolution with the following advantages:

- Ensure that the maximum of capacity calculated year-ahead is allocated to market participants
- Ensure that the split between yearly and monthly products best fit with market participants' hedging needs – instead of a simple split pre-determined in fixed rules
- Circumvent the liquidity problems observed on secondary markets for LTTRs in certain regions.

Allocation of cross-border transmission capacity in further ahead than one year would improve the liquidity of forward markets. It would also offer longer-term hedging opportunities across border which would be particularly helpful in the uptake of cross-border PPAs. All this will reinforce the contribution of forward markets to the development of RES-E and their integration into the market.

15. Do you see value in developing new durations of long-term transmission capacity products mirroring products for forward electricity trading?

We invite the TSOs to study to possibility of calculating cross-zonal capacity more than one year in advance of delivery and of consequently issuing LTTRs in Y-2 or Y-3. LTTRs issued at even longer time horizons than one year in advance would contribute to the uptake of cross-border PPAs.

16. Do you see other means to improve the forward markets and hedging possibilities besides long-term transmission rights?

No, a basic requirement for a liquid forward market that allows for good hedging is a sufficiently liquid bidding zone with a sufficient number of market participants. The bidding zone review methodology should therefore properly address this aspect as one of the elements to be considered when recommending a new bidding zone configuration.

17. Which potential benefits or drawbacks do you foresee with the co-optimisation of energy and balancing capacity?

While we understand that the development of the methodology proposal is a requirement of the EBGL, we invite TSOs and NRAs to refrain from implementing any of the cross-border capacity reservation processes for balancing purposes, whether it be co-optimisation or one of the two other options to be potentially developed at regional level (so-called “market-based” or “economic efficiency” allocation methods)².

Co-optimisation was sold to decision-makers as a rigorous optimisation tool between DA capacity allocation and reservation of capacity for balancing. But because there will still be two merit orders (for balancing capacity bids and SDAC), without possibility to link bids, market participant will need to choose where they bid, hence there is no algorithmic optimisation of capacity allocation.

Other drawbacks for co-optimisation lie in the uncertainty whether the TSO demand for capacity is price sensitive or not, and the unknown effects of the co-optimisation process on the performance of Euphemia. Finally, as the capacity reservation bid matching happens after

² See also [EFET response to the ACER consultation on the TSOs proposal of a methodology for the exchange of balancing capacity or sharing of reserves via co-optimisation \(art. 40 EBGL\)](#)

the co-optimisation process there is also the risk of non-matching, bringing uncertainty not only to the capacity reservation process but also to SDAC.

18. Would you recommend any other solution which could achieve similar objectives?

We do not wish for TSOs to pursue the objective of reserving cross-zonal capacity for balancing purposes.

19. Do you think that the implementation of co-optimisation or other market features could increase market complexity to a level which may be detrimental for the entrance of new players?

Procuring several standard balancing capacity products in a co-optimised manner requires linking not only between balancing and energy-only market bids but also between the different balancing capacity products. Indeed, as per the co-optimisation proposal and the proposal on the implementation of article 25(2) of the EBGL, there will not be just one type but three standard products for balancing capacity. Three product types means that bids would not be the same and BSPs would be forced to choose one of them. Hence, unaccepted bids for one standard balancing capacity product cannot be subsequently offered for another standard balancing capacity product, as it is done currently.

Also, a complex bid in a co-optimised allocation process has to conditionally link bids for the day-ahead market, aFRR, mFRR and possibly RR balancing capacity. The additional complexity introduced appears hardly feasible, not only from a computational point of view for the clearing algorithm, but also for market parties submitting bids.

20. How can TSO procurement of balancing services evolve to be a better fit for the new power system of 2030?

We agree with the general approach proposed in the paper. The fact that TSOs continuously balance the power balance and BRPs continuously manage their energy position, means that TSOs and BRPs interact in the balancing timeframe. We would have appreciated further analysis in the position paper on this crucial aspect.

Defining the role of TSOs and that of Balancing Responsible Parties (BRPs) and their interplay, to ensure the integrity of balancing mechanisms is vital. TSOs are the single buyer in balancing mechanisms and have, as such, significant market power.

Activation of balancing services is only performed based on measured values of frequency and power flows at the borders. Looking ahead to 2030, we propose that all TSOs shall balance power reactively and not proactively.

TSOs should also not be allowed to trade in the DA and ID timeframe. We cannot see how trading by TSOs on the spot markets for balancing purposes can happen as it is the case in some countries. Even during emergency, TSOs may use load shedding and physical interventions in critical situations.

We also question the filtering by TSOs of bids destined to be shared on the European balancing energy platform, as well as their putting a price on their needs (elasticity). Full

transparency on such practices is required, including to assess whether they should continue to be allowed in the future.

Finally, mandatory participation as balancing service providers (BSPs) – especially without remuneration – is against the principle of competitive balancing procurement. If a service is required by the TSOs, it should be procured from freely participating BSPs and paid. As mentioned previously ensuring that pre-qualification requirements and other procedures are not unnecessarily restrictive (e.g. for RES-E installation or DSR) would ensure the participation of greater numbers of BSPs to balancing capacity or energy procurement.

21. Do you have concrete examples of best practices in the procurement of balancing services?

No comment.

22. For system with limited congestions and reactive balancing approaches, would you foresee any benefits to implementing real-time markets managed by the relevant TSO?

We already have real-time markets, albeit not explicitly operated by a TSO, but implicitly through a TSO. This means that BRPs accept open positions if they expect that it supports the system, in effect they are “trading” with other BRPs that have an opposite open position.

This is also based on the concept of self-dispatch that is not restricted in time.

This is not related to the existence/absence of congestions. The principle of self-dispatch means that any generator, storage or consumer can change its output. In case of congestions, TSOs/DSOs may impose restrictions, but such restrictions must be compensated.

We therefore currently see no need to consider real-time markets managed by TSOs. The transparency of congestion management, however, needs to improve in most control areas.

23. Are there any other Balancing Markets enhancement which you would recommend?

The target model for electricity balancing has been under development since well over 10 years, but not yet implemented. Particularly recent years were dominated by many changes in quick succession. The best way to support balancing markets may be to enter a period of more stability. As explained above any further enhancement should only be discussed following the full implementation of existing rules and regulations.

24. Would you support the simplification of products traded in the DA and ID auctions to speed up the implementation of ongoing and future market evolutions?

No. We would not support further simplification. Especially when looking at the 2030 market design and technological evolution, it should be possible for TSOs and NEMOs to handle more complex products by then. At least that is what TSOs and NEMOs should strive to achieve.

We already welcomed the objective and the introduction of “complex products” in SDAC. We also believe that their inclusion can proceed unless proven it has a damping effect on the

algorithm performance, taking account of the planned extension of the algorithm calculation time.

Bilateral trading, also with non-standard products, plays an important role. Therefore, one should not need to strive to capture all system complexities in centralised auctions with complex products.

The market will determine whether new products are needed. And then standardisation can take place, if relevant.

25. If yes, which DA and ID market evolution would you consider to be a priority and which specific products could be discarded?

PUN and MIC could be discarded, provided that related obligations in Italy and Iberia are reviewed accordingly.

The flexibility for market participants should come from the freedom of bidding and the use of “block orders”, including the most sophisticated formats of blocks currently available in Central Europe³.

26. Which potential benefits or drawbacks do you see with the alternative pricing methodologies described above?

We have no view on benefits. Such benefits might be overestimated, if one ignores the bilateral / OTC market.

27. Would you recommend any other solution to improve the performance of DA and ID coupling algorithms?

We defer to NEMOs to present options to improve the performance and reliability of algorithms.

28. Which potential benefits or drawbacks do you foresee by allowing more time for the algorithm optimisation?

We reserve our answer on this topic.

29. Would you be in favour of keeping an hourly auction in day-ahead followed by 15 min intraday auctions?

This question needs to be answered in the context of product granularity. While we support the introduction of smaller granularity products in general and acknowledge this is a legal requirement from Regulation 2019/943, we believe that this represents much less of a priority in day-ahead than it can be in intraday. We are missing a proper impact assessment of the introduction of 15-minute products in day-ahead.

³ See also our [EFET response to ACER consultation on all NEMOs DA products](#)

If 15-minute products in day-ahead are introduced, we could welcome that this is accompanied by a 15-minute auction, provided that Euphemia can cope with the extra complexity. Once again, we defer to NEMOs to inform all parties whether the performance and reliability of the algorithm can be maintained in that context.

As for intraday, while we support the introduction of 15-minute products (including across borders), we refer to our answers to questions 9 to 13 and maintain that the most effective manner to match bids and offer and allocate cross-zonal capacity remains with continuous trading.

30. Would you recommend any other solution to adapt market coupling procedures?

No comment.

Congestion Management & Spatial Granularity

31. Do you think the zonal market model including the planned evolutions of the Clean Energy Package is suitable for the 2030 power system?

Yes, it is. The zonal model induces a compromise between network management efficiency and market functioning efficiency.

The main challenge is to perform a proper bidding zone review. Any assessment of existing bidding zones delineation and possible review of their boundaries should be based on an equally thorough analysis of network congestions and market efficiency⁴. There is still too little understanding of the impact of liquidity of forward markets on social welfare, and so far, little hope that the bidding zone review methodology will allow to take full account of that aspect in future reviews.

Also the delay in implementing coordinated methods for cross-zonal redispatching and countertrading is a major concern.

32. What is the most important feature of the current zonal market design that must be adapted to make it future proof?

In the next BZR, we recommend going back to the drawing board on the model-based scenarios and making sure that the results from the future clustering exercise, even re-processed and as politically sensitive as they may appear, be analysed according to the welfare maximisation metric like any expert-based scenario. We strongly suggest reviewing bidding zones configuration from a neutral perspective (including disregarding national boundaries), i.e. being open not only to splitting them, but also to maintaining or merging existing bidding zones as well as a combination of splitting and merging. Offshore grids should also be included in the BZR of the future.

We suggest simplifying the modelling of the effect of alternative bidding zones delineations on the management of networks as well as the functioning of markets. Modelling flow-based in

⁴ See also [EFET position paper on bidding zones - Lessons from the past and recommendations for the future](#)

the future also has its significant share of uncertainties (beyond the fact that it solely focuses on DA markets). A reasonably representative modelling of network management and market functioning would simplify the analysis and be more helpful.

Any review of bidding zones ought to include a serious and thorough quantitative analysis of market efficiency in different bidding zone configuration scenarios. We insist the analysis of efficiency must extend to study of liquidity and competition effects of any re-delineation of bidding zones, alongside the physical elements needed to keep the grid stable.

Another important feature of the current zonal market design to make it future-proof is to implement coordinated methods for cross-zonal redispatching and countertrading.

33. Which potential benefits or drawbacks do you foresee with introduction of the PST and cross-border/internal HVDC in the allocation phase of transmission capacities alongside the market coupling?

The idea is interesting, although it is difficult to assess the drawbacks and benefits.

We would appreciate an analysis of the application of this idea to the ALEGrO cable. What was the impact on market results? What were the benefits?

34. Which potential benefits or drawbacks do you foresee with the introduction of several Flow-Based domains in the allocation phase of transmission capacities?

The idea is interesting, although less obvious than the introduction of PST&HVDC in market coupling. It is also difficult to assess the benefits. A potential drawback could be that it becomes more complex to forecast prices.

35. Do you see the Dispatch hubs model as a promising option to be further analysed in the future? If so, which variant: Redispatch potential bids or market bids appears the most promising?

Once again, the idea may be interesting but we would welcome further analysis by the TSOs on this topic. A major drawback of the dispatch hub concept would be the reconsideration of portfolio optimisation and portfolio bidding by market participants.

36. Do you foresee any challenge in the implementation/ operation of the model?

The algorithm complexity may increase with such solutions. This is something that we also observe at DSO level. We defer to NEMOs to inform all parties whether the performance and reliability of the algorithm could be maintained in the context of this model.

We also fear that the concept of "dispatch hubs" entails a strong element of DA unit bidding rather than portfolio bidding that we would not support.

37. Do you consider more locational information in the balancing timeframe to be a solution worth requiring further analysis?

We wonder if more locational information in the balancing timeframe would lead to a mix up of balancing with congestion management. This should not be the target.

The idea to have more location information in the balancing time frame (or actually at any time frame) is at odds with the zonal market design. In the zonal market price, there is uniform pricing in that zone, irrespective of the location. Also, it would come to the detriment of a portfolio bidding approach.

TSOs must obviously be able to manage congestions and this does require locational information. But congestion management measures (like redispatch or like not allowing a market participant to deviate from its schedule) must be seen as interventions in the market, that may be necessary but must be compensated.

When looking at congestion management, all market timeframes (e.g. DA, ID...) should be considered.

TSOs sometimes filter balancing bids in the EU balancing platforms for congestion management purposes. This is undermining the level playing-field of BSPs in Europe. More transparency on bid filtering by TSOs is required. Bid filtering should be flagged as congestion management and compensated accordingly.

38. Would you recommend any alternative solution to solve intra-zonal congestion in the balancing timeframe?

TSOs may have a right to declare balancing bids “unavailable” in case of congestions, such intervention must be regarded equivalent to a redispatch measure and must therefore be compensated. Otherwise there is a violation of the self-dispatch principle. If a market participant is restricted in its right to self-dispatch, then this must be compensated.

39. Do you think experience with nodal models can be useful in Europe, and how?

We agree with ENTSO-E view that nodal is not a feasible/desirable option in Europe.

40. What other advantages or disadvantages do you foresee with nodal models in a European context than those mentioned here?

We agree with ENTSO-E’s analysis.

In order to assess the impact of the calculation of imbalance prices based on nodal balancing prices, more information and explanation about what is meant with this concept would be needed. What would be the actual nodal configuration used for computations? What is the evidence available insofar as to the geographical/service/perimeter configuration of such nodes across Europe?

Moreover, nodal pricing implies a complete, fundamental overhaul of current grid management and electricity trading arrangements with very substantial transition costs.

In addition, most academic papers on nodal pricing including reports from US nodal markets, normally ignore the downside of lower liquidity of forward markets, or – to be more precise – higher costs for hedging.

41. How could the increasing participation of distributed energy resources to the balancing market be handled in nodal pricing models?

Nodal design and central dispatch are not the best solutions to integrate demand-side flexibility or intermittent RES-E (driven by weather conditions, not central unit dispatch). In the US nodal models, ISOs started introducing zonal elements to integrate demand side flexibilities.

42. Under which conditions do you think a nodal market could be a relevant solution for some countries?

A nodal market is not desirable. One further reason is that hedging will become more difficult and hence more costly in a nodal system.

No exceptions to zonal pricing should be considered.

43. Do you foresee other challenges or solutions than those mentioned here with respect to the interaction between zonal and nodal solutions?

There is the need to overcome national political resistance to merging of national control areas to form larger zones and/ or to organising zones which transcend national borders, by including only part of a neighbouring national territory.

Moreover, the power market does not consist of isolated market segments like forward, day-ahead, intraday and balancing. Instead, these segments of the market are interrelated and market parties optimise their assets across these different time frames. This also means that market parties can take open positions in one segment, if they expect better prices in the other segments and if they are flexible to respond to such prices. This results in the most efficient dispatch.

Ultimately, the main price signal is the imbalance price, as metered physical positions are exposed to the imbalance price. All other prices (including day-ahead and intraday) are forward prices and can be considered as a hedge towards the imbalance price. And therefore the prices of all segments of the power market in a zone, must be zonal. The idea to apply nodal in the balancing time frame actually means a choice for nodal in all timeframes.

44. How can distortions and inc/dec gaming in market-based redispatch be addressed/mitigated?

REMIT already addresses the inc/dec gaming.

45. What type of alternatives (e. g. capacity-based payments) exist to efficiently make use of distributed flexibility sources?

Flexibility is the ability to use/exploit capacity without limitations – thus flexibility is a characteristic of capacity but not a product in itself. Capacity is “flexible” if there are limited constraints to use the capacity as needed.

Flexible capacity is valued in the energy market and via TSO procurement of congestion management services, hence no separate “flexibility market” exists. It is through these competitive mechanisms that distributed flexible capacities will be valued and most efficiently used.

46. What recommendations do you have for the development of local flexibility markets based on existing initiatives?

DSR and distributed resources should be allowed to participate in the TSO’s existing balancing and ancillary services mechanisms on its own or via an aggregator, as well as on the electricity market. To deliver this capability we do not consider that there is a need to develop an additional separate market, in particular as their participation is mainly dependent on the regulatory arrangements of already existing markets and establishing the necessary coordination processes between TSOs and DSOs to ensure system security at both grids.

The use of flexible capacity for the purpose of congestion management by DSOs needs instead more profound consideration. We highlight that any new proposal for a local market, should first make sure to provide a link between local products/markets and the wholesale market to ensure that the price signal is sufficiently strong and minimise the risk of excessive market power. Appropriate measures must be taken to avoid market power abuse and gaming risk, and management of localised congestion management should in any case not lead to the fragmentation of current balancing mechanisms and/or electricity markets at zonal level and to pursue an integrated system approach when developing new solutions and to avoid any isolated solution.

47. Should EU legislation attempt to define some fundamental common principles (e. g. degree of integration with existing wholesale markets, products standardisation, etc.)?

Yes, valuing flexible capacity via system operators’ procurement of congestion management products and services in an efficient manner will require a clarification of the regulatory framework. The explicit procurement of redispatch by system operators, which does not constitute a market as such, should be organised in a true competitive manner.

All in all, what matters is the optimisation of both the market and the system, for the benefit of society. Looking ahead, a number of proposals are emerging to improve the optimisation of welfare in the electricity system⁵. We warmly welcome an open debate to ensure that the valuation of all flexible capacities in the electricity market is enabled, and to provide a clearer and stronger framework for the management of internal congestions. Thorough analysis of the various proposals and unbiased return on experience of pilot projects should be carried out to inform future decisions on the design of the energy-only market and congestion management mechanisms.

Resource Adequacy and Investment Signals

⁵ See, for instance, the Elia Group Study on [Future-proofing the EU energy system towards 2030](#).

48. Do you agree that all three models described above could be suitable for European countries in 2030?

Generation, storage and demand adequacy should be assessed at pan-European level. As far as possible, the energy market (EEM) should be left to answer inadequacies in capacity. We recognise that in a decarbonising economy, featuring greater penetration of renewable energy production involving inherent intermittency, payments to guarantee the availability of standby capacity can be considered in order to supplement a weak or unreliable investment signal by an energy only market.

Should a capacity remuneration mechanism (CRM) be considered necessary in a Member State, it should not serve as a substitute for efforts to improve the energy market's ability to answer capacity adequacy problems. A capacity remuneration mechanism, if introduced, should be non-discriminatory, open to cross-border participation and transitory in nature. All generation capacity (including RES-E), storage and demand side response should be allowed to participate in the capacity mechanism as per art. 22 of EU Regulation 2019/943.

49. Is there any additional market model which would be suitable for European countries in 2030?

Please see our answer to question 48.

50. Do you see capacity mechanisms with flexibility requirements as a promising option for further analysis?

The availability of flexible capacity becomes ever more crucial as intermittent production sources become predominant. And thus it will be ever more important that the operation of the energy market should be free from artificial regulatory interventions, intended to suppress price volatility. We therefore see no added value in integrating flexibility requirements into a capacity market design. The purpose of a capacity market is to ensure that sufficient firm capacity is available when it is needed.

51. What are in your view the main potential advantages and drawbacks of capacity mechanisms with flexibility requirements?

If pursued, the design must ensure that it does not lead to a capacity mechanism for certain generation assets with a technology lock-in effect for the transition to carbon neutrality.

52. Do you consider the capacity subscriptions model as a promising option for further analysis?

Yes, further analysis might be needed. Consumer based approaches should be capable of providing a demand side signal for adequacy and reliability. It is a concept that has already been tested for grid tariffs in some Member States.

It would be interesting to investigate whether new innovative contracts with capacity subscriptions are being offered on a voluntary basis by retail suppliers and to assess whether such contracts have a positive impact on the functioning of the EEM.

53. In your view, what are the main potential advantages and drawbacks of the capacity subscriptions model?

These measures could enhance consumer engagement through response to price signals.

The main advantage would be that the customer get what they want and for what they are willing to pay. Whether the rather short-term structured capacity subscription model offers the right framework or financial incentives for this is at least unclear.

54. Which potential benefits or drawbacks do you foresee with the implementation of scarcity pricing in your market?

We objected before that in case a TSO identifies the need for stronger incentives in scarcity situations, the TSO should not propose to its relevant regulatory authority to apply a scarcity or an incentive component in imbalance pricing.

The aim however should always be to set the imbalance price at the value of electricity in real time.

55. Do you have any specific suggestions on how scarcity pricing could be implemented?

Floors and caps should have been removed by the 1st of January 2020 as stated in art.10 of EU Regulation 2019/943. Full implementation has to be accelerated in all member states.

The application of scarcity price adders on BSPs (both in energy and capacity prices) bounces with legal obstacles. Moreover, it is hardly compatible with the prevailing market design and would have discriminatory effects and potentially distort the functioning of European markets:

Art. 44.1(b) EBGL states that the imbalance settlement price should reflect the “real time value of energy”. The real time value of energy naturally takes account of the risk of scarcity. Therefore, if properly set according to the EB GL principles, the imbalance settlement price should de facto provide an adequate price in situations of scarcity.

In addition, if implemented in a non-coordinated way, such additional components would lead to different imbalance price behaviour with similar imbalance volumes in the different control areas. Their use should be harmonised through the definition of an imbalance price methodology, instead of creating additional components as currently proposed.

Only in case of a scarcity caused brown-out (load shedding), the value of that intervention must be reflected in the imbalance price. For this reason, it must be checked whether for these periods the imbalance price would remain below (an assessment of) the VoLL and in such case the imbalance price must be increased to the VoLL.

56. What type of RES supports is more fit for purpose for the 2030 power system?

In discussing the need for continued financial support for RES-E, it is important to draw a distinction between existing installations, which have already recovered their investment costs

through existing or previous support schemes, and new projects, which still need to secure their capital investment.

We analysed several policies in Europe and the different impacts they have on market functioning. Financing of RES-E should come first and foremost from the wholesale electricity market, complemented if possible, by revenues from the retail market via the marketing of GoOs or the conclusion on PPAs. If financial support schemes for RES-E are deemed to be necessary, then they should achieve the target build out of RES-E at minimum cost, minimise system operation distortions, involve competitive allocation, preserve exposure to market prices and operate across borders.

Furthermore, a well-functioning CO2 emission pricing system based on EU ETS is the corner stone for the development of RES.

57. What other market design elements can facilitate investments in RES to achieve EU climate objectives?

Please see our answer to question 56.

58. What are the best practices for the design of RES tenders?

Few key principles that should be considered for the design of RES tenders:

- Tenders should be generally clear, simple, transparent and focus on the objective of delivering those RES projects which offer the lowest difference cost for consumers and taxpayers.
- Competitive allocation where the price should be the only deciding factor on whether a tender is awarded or not as this is most transparent and non-discriminatory.
- Preserve exposure to market prices and not distort the level playing field (e.g. no preferential treatment of specific investor groups)
- Operate across borders
- Achieving the RES-E build out

59. How should capacity mechanisms consider the participation of RES?

Where CRM exist, RES-E should be fully entitled to participate, provided they do not receive other forms of financial support, in order for TSOs to secure adequacy efficiently.

60. Do you see potential for the development of new frequency ancillary services?

Due to the decommissioning and elimination of more and more conventional generation capacity and thus less and less rotating mass in the grid, we recommend the development of new ancillary frequency services in the areas of ultra-fast frequency or spinning reserve. TSOs should always procure those service from the market.

61. Which non-frequency ancillary services are more suited for market-based procurement?

All ancillary services need to be procured in a market-based and technology neutral way.

The consultation document does not discuss the issue whether TSOs/DSOs should be allowed to own assets that can provide ancillary services. In this respect, we would like to refer to the [advice](#) of the ENTSO-E advisory Committee.

The Clean Energy Package defines the products for the procurement of non-frequency ancillary services that should be procured by system operators from market participants. These are in particular steady-state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current and black start capability. It should be the focus of any Member State to implement these accordingly and limit national diversions/exemptions in order to create a level playing field in the competition for the provision of non-frequency ancillary services. Only if the requirements by the TSOs are communicated in detail, market participants can respond to the needs identified by the TSOs. To date however, different national strategies exist while TSOs move on with their own investments. These should undergo a market test and be transferred to market participants in line with the Electricity Directive.

62. Do you have suggestions on how to best ensure that market participants provide the necessary system inertia to the system?

TSOs need to define products and terms, ideally at EU level, in order to procure it in a market-based manner including via pooling and aggregation. Competitive tenders promote competition and provide visibility of revenues in the medium/long term.

63. Would you recommend any other solution for ancillary services in 2030?

Besides power generation, the contribution of demand side response and storage in the delivery of balancing capacity and energy (FCR, FRR and RR) and non-frequency ancillary services must be possible. This requires that TSOs accept offers where market participants aggregate different capacities into a pool. Likewise, electricity storage operators should be allowed to bid into balancing capacity and energy auctions, including via pooling. The TSOs should make sure they allow market participants to link or make bids conditional to ensure that the widest diversity of capacity owners can contribute. Where barriers exist to the participation of demand response or storage to balancing mechanisms, these should be removed.

It will be critical to implement a harmonised coordination process between TSOs and DSOs to allow the participation of all the assets connected to both grids to participate in all the ancillary services markets. Constraints at the DSO grid obviously have to be considered, but since markets will operate closer to real time, the procurement has to consider all validated bids for local flexibilities.

64. Is there any other key market design area not addressed in this paper which deserves particular attention to enable the achievement of European energy and climate goals for 2030?

No comment.