

# ACER-CEER

## Reaction to the European Commission's public consultation on electricity market design

14 February 2023



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## 1. Introduction

This document is the joint response of the EU Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) to the European Commission's [public consultation on the reform of the EU's electricity market design](#). The joint response was submitted via the European Commission's online questionnaire system on 13 February 2023.

It comprises the ACER-CEER replies to the **questions** asked by the Commission in its consultation as well as additions to the replies in the **Annex** (also submitted to the Commission as part of our consultation response)<sup>1</sup>. In the Annex, ACER and CEER delve deeper into elements that are subject to consultation:

1. contracts for difference; and
2. obligations on suppliers to offer fixed-price contracts to household consumers.

In addition, the Annex highlights several important aspects of the electricity market design framework that were not addressed by the Commission in its consultation, yet in our opinion, have a significant impact on electricity market functioning:

3. The adequacy of minimum cross-zonal electricity capacity requirements
4. The importance of the integrated intraday and balancing market
5. Continuous growth of implementation delays in key integration projects
6. The adjustment mechanism for decrease of maximum clearing and bidding prices
7. Legal framework for offshore wind

The Commission's consultation period was from 23 January 2023 to 13 February 2023.

ACER and CEER in their response welcome the Commission's attention to long-term markets as the key enabler for investment stability and affordability for consumers.

The ACER-CEER response is public and can also be found on the European Commission's website.

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<sup>1</sup> Please note that the Annex as submitted online had some additional points that could not fit (due to character limits) in the online response. However, in this document, those points are instead inserted under the relevant question.

# 1. ACER and CEER responses to questions raised in public consultation

## 1.1. Making Electricity Bills Independent of Short-Term Markets

### 1.1.1. Power purchase agreements

#### 1. Do you consider the use of PPAs as an efficient way to mitigate the impact of short-term markets on the price of electricity paid by the consumer, including industrial consumers?

*ACER/CEER response:* Yes.

#### 2. Please describe the barriers that currently prevent the conclusion of PPAs.

ACER/CEER response: By PPAs, ACER and CEER understand corporate PPAs, which are bilateral contracts between private market participants with either physical delivery or purely financial obligations. The contracts are tailor-made and assign risks and costs according to the wishes and needs of those participants. First, we emphasise that there is an inherent mismatch between (i) the hedging interest of most consumers, as they are not interested to be locked-in on prices for very long horizons and (ii) the producer hedging interest, as they want to hedge their investment costs. Furthermore, in some Member States, the current support schemes for renewable energy sources can limit the willingness of producers to enter into such agreements. Due to the lack of standardisation and bilateral nature of PPAs, the supply and the demand for PPAs are difficult to match. It is therefore a complex task for generators (on one side) and consumers (on the other side) to identify and initiate the set-up of a PPA, especially across borders, because cross-zonal capacity cannot be allocated in such long timeframes.

Furthermore, small consumers or suppliers often have limited access to PPAs as they have difficulties in demonstrating their bankability and their ability to honour their obligations. They might also have varying time horizons or needs in terms of volumes to offtake, as well as a counterpart risk mismatch. Additionally, PPAs are less flexible in the sense that the bilateral arrangements are mutually binding during the contract maturity or with costly exit clauses.

However, if PPA contracts were to be standardised and if supply and demand were pooled through more organised marketplaces, it would then be important for Member States to assess whether to support PPAs or instead to channel such trades through regular financial contracts such as futures, forwards and options with same maturities. If some Member States choose to provide support and guarantees to PPAs (e.g. by providing state guarantees to participants with physical assets), such support could instead be provided to fulfil the collateral requirements towards the clearing houses at organised marketplaces. This would drive more trade onto exchanges (which is preferable to supporting bi-lateral PPAs) increasing transparency, forward market liquidity and competition.

#### 3. Do you consider that the following measures would be effective in strengthening the roll-out of PPAs:

##### (a) pooling demand in order to give access to smaller final customers

*ACER/CEER response:* Yes.

##### (b) providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks)

*ACER/CEER response:* Yes.

**(c) promoting State-supported schemes that can be combined with PPAs**

*ACER/CEER response:* Yes.

**(d) supporting the standardization of contracts**

*ACER/CEER response:* Yes.

**(e) requiring suppliers to procure a predefined share of their consumers' energy through PPAs**

*ACER/CEER response:* Yes.

**(f) facilitating cross-border PPAs**

*ACER/CEER response:* Yes.

**Do you have additional comments?**

*ACER/CEER response:* Overall, PPAs are bilateral arrangements, which may be a welcome addition to the forward market, but ACER and CEER refrain from actively supporting PPAs because they may have a negative impact on overall market efficiency and transparency. Given their characteristics, they are not suitable to all market participants.

All the above measures would support the roll-out of PPAs, however they come with many undesired consequences:

- (a) Pooling of demand may or is already provided by various service providers and brokers based on the interests from market participants. Yet, it is important to emphasise that PPAs are highly customisable contracts, and it may be hard to establish a multilateral or standard contract, where all parties agree on the contract specification and who covers the volume risk. Also, it is questionable whether there is an interest from small consumers to enter such long-term contracts.
- (b) ACER and CEER are not in favour of EU-wide obligations for Member States to provide state insurance for counterparty risk. Yet Member States may be allowed to do that at national level. This instrument should only be implemented after a thorough assessment of the negative effects on other Member States and the European electricity market and only with a State Aid approval. In case of negative effects these instruments should only be implemented if the benefits surpass the cost at a European level.
- (c) Standardisation of PPAs is welcomed, but financial futures and forward are already standard long-term products that serve the same purpose. CfDs seem also better suited for standardisation. If some Member States decide to facilitate higher volumes and more standard PPAs, then it might be better to put such effort in supporting financial forward markets with futures and forwards.
- (d) Putting obligations on suppliers would be good for PPAs, but ACER and CEER in general advise against putting EU-wide obligations on suppliers to hedge beyond the volumes and maturities of fixed price contracts they have with consumers. Such obligations would have a significant impact on the risk-management of suppliers and the price policy towards their consumers. Nevertheless, some Member States could put such obligations at national level, as long as this is implemented after a thorough assessment of negative effects on other Member States and the European electricity market and only with a State Aid approval. In case of negative effects, these instruments should only be implemented if the benefits surpass cost at a European level.

Facilitating cross-border PPAs would theoretically be welcomed but it is hard to imagine how this could be done without the necessary transmission capacity allocation by TSOs to facilitate trading. Capacity allocation in timeframes of 10-20 years is unimaginable in the present and foreseen future.

**4. In addition to the options proposed in question 3, do you see other ways in which the use of PPA for new private investments can be strengthened via a revision of the current electricity market framework? If yes, please explain which rules should be revised and the reasons.**

*ACER/CEER response:* No.

**If no, please explain.**

*ACER/CEER response:* There might be other ways to strengthen the use of PPAs. However, ACER and CEER recommend refraining from actively supporting PPAs and instead propose that state support is directed to other forms to improve the liquidity of forward markets.

- 5. Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity? If yes, under which conditions? What would be the benefits and challenges?**
- 6. Do you consider that stronger obligations on suppliers and/or large final customers, including the industrial ones, to hedge their portfolio using long term contracts can contribute to a better uptake of PPAs?**

*ACER/CEER response:* No.

**If no, please explain.**

*ACER/CEER response:* ACER and CEER are not in favour of EU-wide obligations on suppliers to hedge beyond the volumes and maturities of fixed price contracts that they have with consumers. Suppliers would be exposed to unreasonable risks if they would need to enter long-term contracts, but not be covered by long-term contracts on the consumer side. Such a situation would exacerbate the risk of supplier default and could eventually reduce consumer protection. ACER and CEER are not in favour of such obligations put on large industrial consumers. Nevertheless, some Member States could put such obligations at national level, as long as this is implemented after a thorough assessment of negative effects on other Member States and the European electricity market and only with a State Aid approval. In case of negative effects, these instruments should only be implemented if the benefits surpass the cost at a European level.

**7. Do you consider that increasing the uptake of PPAs would entail risks as regards:**

**(a) Liquidity in short-term markets**

*ACER/CEER response:* Yes.

**(b) Level playing field between undertakings of different sizes**

*ACER/CEER response:* Yes.

**(c) Level playing field between undertakings located in different Member States**

*ACER/CEER response:* Yes.

**(d) Increased electricity generation based on fossil fuels**

*ACER/CEER response:* No.

**(e) Increased costs for consumers**

*ACER/CEER response:* Yes.

**If yes, how can these risks be mitigated?**

*ACER/CEER response:*

- (a) Promoting PPAs means promoting bilateral trading, which means that the MWs or MWh covered by these PPAs will inevitably disappear from the volumes in the forward and day-ahead market if those PPAs are physically settled (there may be some forms of PPAs where this negative effects would not occur). If Member States or regulatory authorities decide to support the long-term market with specific interventions, then such support should promote trading at organised market places with standard financial contracts (e.g. futures and forwards) that promote transparency, efficient price formation, standardisation and have no impact on the liquidity of short term markets.
- (b) PPAs due to their inherent customisation and non-standardisation are suitable for bilateral agreements but less suitable for portfolios of small players. Suppliers could bridge this gap by pooling the different interests of consumers.

- (c) If the rules governing regulatory and state support to PPAs are not harmonised, then this will affect the level playing field in different Member States. Nevertheless, some Member States could design such rules at national level, as long as this is implemented after a thorough assessment of negative effects on other Member States and the European electricity market and only with a State Aid approval. In the case of negative effects these instruments should only be implemented if the benefits surpass the cost on a European level.
- (d) N/A, see below
- (e) Yes, long-term contracts provide opportunities for affordable prices but it also risks customers getting locked in at a high price. Long-term contracts with investors represent competition for the market. Such competition is weaker than competition in short-term markets, because of a very limited supply and demand at any given moment and no cross-border competition. Hence, consumers might on average be faced with higher costs of electricity supply. Signing a long-term contract to buy electricity is very risky if the hedge is not covered on the sell side (e.g. selling aluminium to be produced for the same period).

**If no, please explain.**

*ACER/CEER response:*

- (d) ACER and CEER cannot see reasons why an increase in the uptake of PPAs would lead to an increase of fossil-based electricity generation.

### **1.1.2. Forward Markets**

#### **1. Do you consider forward hedging as an efficient way to mitigate exposure to short-term volatility for consumers and to support investment in new capacity?**

*ACER/CEER response:* Yes.

#### **2. Do you consider that the liquidity in forward markets is currently sufficient to meet this objective?**

*ACER/CEER response:* No.

#### **Do you have additional comments?**

*Options for response: max 2000 characters*

The liquidity of a forward market is a key parameter for it to be able to offer efficient hedging opportunities. Currently, only the German bidding zone has sufficiently high liquidity in its electricity forward market (and even then, only for futures products up to three years to delivery). Hedging products of all other EU zones have liquidity issues, which directly impact the hedging opportunities of the market participants. Over the last years, it seems that as a general trend across the continent, the liquidity of the forward markets is decreasing.

Poor liquidity for a hedging product increases the bid-ask spread and forces market participants on one side to pay higher risk premium (and the other side receiving it) or to find proxy hedging solutions in other zones which very often do not protect against the risk sufficiently.

#### **3. In your view, what prevents participants from entering into forward contracts?**

*ACER/CEER response:* ACER and CEER consider that this is partly an issue of the long-term market design, structure and its requirements (including financial) and partly an issue of the inherent incentives and interests of market participants (MPs) to hedge.

Regarding the market design, the issue of the forward market fragmentation into different bidding zones (BZs) and trading venues is the most problematic issues. In Continental Europe, forward markets are organised in each BZ separately and, except the German BZ (serving as an unofficial proxy hedging hub), all other BZs have insufficient and poor liquidity. Nevertheless, such proxy hedge may not cover the risk efficiently and significant shares of the forward trading is still scattered in smaller BZs. This problem creates a discrimination in the market access and a non-level playing field between the MPs of smaller BZs and those of bigger BZs.

The existing framework of allocating long-term transmission rights is contributing to this problem because they are not integrating national forward markets into an integrated EU forward market especially because of their low accessibility (low frequency of auctions, low volumes, inadequate maturities).

The market structure has a significant impact on market liquidity (e.g. high horizontal/vertical integration, supply/demand asymmetry). Some structures present disincentives to hedge to some/all participants and therefore impact the liquidity.

On the side of the hedging incentives, we have identified policy measures that remove the spontaneous incentives of MPs to hedge their risk in the forward electricity market (e.g. generation-type specific subsidies, state contracts, retail/wholesale price regulation...).

The collaterals that need to be placed by MPs to trade in organised marketplaces (required to properly manage counterparty risks but not tailored to the energy market) and other exchanges rules (size of products, fees) can also present a disincentive to hedging at exchanges.

**4. In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?**

*ACER/CEER response:* No.

**Do you have additional comments?**

*ACER/CEER response:* This measure would have a positive impact on the liquidity of the forward market (especially beyond 3 years ahead). However, such obligations would have more negative impact on consumers and retail competition.

In general, ACER and CEER are not in favour of hedging obligations on suppliers, which would exceed the volume and maturities of fixed-price contracts they are able to settle with their consumers. The situation where a supplier is required to hedge its current or forecasted portfolio far in the future years ahead, without being backed by relevant fixed-price contracts with consumers, represents a significant risk for suppliers as they are obliged to honour hedging contracts at the wholesale side but are exposed to consumer switching at retail side. This risk may cause the suppliers to go bankrupt which would undermine protection of consumers and retail competition. This risk could potentially be mitigated with a proper framework for contract termination fees or with a mechanism allowing to transfer the hedging obligations between suppliers in case of consumer switching. However, both of these solutions seem rather complex and cannot be recommended at this moment.

Nevertheless, if some Member States find ways to mitigate these risks, they should be allowed to impose such obligations at national level. This instrument should only be implemented after a thorough assessment of negative effects on other Member States and the European electricity market and only with a State Aid approval. In case of negative effects these instruments should only be implemented if the benefits surpass cost on a European level.

**5. Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets?**

*ACER/CEER response:* Yes.

**If yes, do you consider that such virtual hub(s) should be developed at national, regional or EU level?**

*ACER/CEER response:* Regional level.

**Do you have additional comments?**

*ACER/CEER response:* Virtual hubs can represent a partial solution to the problems mentioned previously (market fragmentation, structure of the market) but also to other problems such as the current vulnerability of the forward market to bidding zone (BZ) reconfigurations.

Indeed, such hubs pool the liquidity of multiple BZs into one hub and reduce the discrimination faced by the smaller BZs due to their size, but they also reduce the impact of inadequate market structure. Also, a reconfiguration of BZs should have no significant impact on the liquidity of the forward market at the hub, which addresses a key concern of BZ reconfigurations in the current zonal market design.



To allow market participants to efficiently cover the bigger share of their risks, trading hubs must attract a sufficient “critical mass” of supply and demand bids for hedging. To achieve this, the price of those hubs must present significant price correlation with the prices of the BZs (>95%) and market participants must be able to cover efficiently the remaining risks through cross-zonal products (such as transmission rights (TRs) or the Nordic Electricity Price Area Differential (EPADs)) issued from zone to hub. For the two above-mentioned reasons, virtual trading hubs defined at a regional level are the best to achieve this goal.

Such a design could have some positive impact on forward market liquidity beyond 3 years (assuming it combines the liquidity of all bidding zone under a hub), however this remain uncertain as liquidity development is hard to predict.

Finally, the creation of virtual hubs raises some technical challenges which include the formulas to determine the hub price, the geographical perimeter of the hub, the type of cross-zonal products (TRs or cross-zonal CfDs) associated and the liquidity risk in case of poor price correlation between the hub and BZs. ACER and CEER see the need for further discussion on these open topics with stakeholders and proper impact assessment in order to maximise the benefits and minimise the risks of any proposed reform.

## **6. Do you have experience with the existing virtual hubs in the Nordic countries?**

*ACER/CEER response:* No.

## **Do you have additional comments related to the existing virtual hubs in the Nordic countries?**

*ACER/CEER response:* The Nordic forward market hub product has been successful in providing more liquidity than a forward market in each individual zone would have had otherwise, especially considering that Nordic countries are subdivided in many small bidding zones. Considering this bidding zone configuration, a Nordic forward market hub is the only possible option to have an efficiently working forward market. However, the cleared volumes of the Nordic hub product have gradually decreased since 2008. This liquidity drop has been generally affected by the same elements that affected other power futures derivatives in Continental Europe, namely: the 2008 financial crisis, the EMIR Regulation in 2016, and the MIFID II Regulation in 2019. Furthermore, the correlation of the hub price with the zonal prices has decreased during the energy crisis from 2021 onwards. This lower correlation could be mitigated with EPAD contracts. However, volatile prices and large degree of uncertainty have caused low liquidity in EPADs. This also contributes to lower liquidity of the Nordic hub.

Increased liquidity in the EPAD market could make the Nordic hub more attractive. Unless proven to be adequate, the liquidity of EPADs could be supported by TSOs with long-term capacity allocation or by introducing zone-to-hub FTRs. Market makers could also be introduced to additionally boost liquidity. It could also be assessed whether the hub price definition should be improved to offer better correlations between the hub price and the price of the zones. However, it should be noted that the hub price definition is currently not regulated. Finally, as in the case of other derivatives, a review of collateral requirements would probably also have a positive impact on the Nordic forward hub. Currently, the Nordic hub derivatives are partially traded on the exchange, and partially traded through brokers or OTC bilaterally. The drivers and barriers as well as costs and benefits of trading in and outside the exchange should be further assessed.

## **7. In your view, what would be the possible ways of supporting the development of forward markets that could be implemented through changes of the electricity market framework?**

*ACER/CEER response:* Regarding the forward market up to 3 years ahead, we identify several potential improvements:

- Reduce hedging disincentives by designing better investment support (e.g. RES subsidies, CfDs) and/or consumer protection schemes that have less negative impact on forward markets
- Revise the Regulation on Forward Capacity Allocation to introduce several changes:
  - Introduction of regional hubs complemented by zone-to-hub TRs.
  - Improvement of the access to FTRs with adequate cross-zonal capacities, longer term maturities, more frequent auctions and secondary market through continuous access.

- Allowing TSOs and regulatory authorities to support forward markets through multiple means (e.g. complement TRs or other forward hedging products with market making).

The measures described above for markets up to 3 years ahead could also strengthen the markets beyond 3 years. However, as the effect would at best be rather limited, additional or other measures would be needed to improve the functioning of markets beyond 3 years ahead. We identify in this market segment a fundamental discrepancy between the hedging interests of most consumers and the producers. Producers will seek to secure their investment and are keen to establish contracts on long durations to do so ("investment hedge"). Most consumers, on the other hand, have little incentives to hedge beyond a period of 3 years ("operational hedge"), even though a long-term hedge could render their prices more secure.

To bridge this gap, we identify 3 policies that could further strengthen the forward market beyond three years ahead:

1. Adjusting collateral requirements and risk management policies at organised marketplaces defined in the financial regulation to have them better fitting the energy markets (e.g. reducing collateral requirements or their required quality or reducing risk management standard) possibly combined with state guarantees for participants with physical assets (producers, consumers).
2. Adjusting trading and settlement arrangements (for example instead of continuous trading, auctions could be organised).
3. Educating consumers about risks and opportunities when entering supply contracts. This should include the benefits of long-term fixed price contracts, potentially linked to collective investments in generation capacity, as well as their possible risks. This may be complemented with clear signals of government inviting consumers to seek protection themselves if they want to be protected from high prices.

These improvements would have to be tailored to maximise competition and find the right balance between risk management and associated costs.

Nevertheless a missing forward market beyond three years does not necessarily mean that producers are not able to hedge far in the future. A common practice to hedge risks far in the future is rollover hedging. In this type of hedging, market participants hedge volumes far in the future with products closer to maturity, which are more liquid. With time, when a contract with longer maturity becomes more liquid, they sell the close mature contract and replace it with a contract with longer maturity of equal volume. Assuming high correlations between consecutive contracts, this strategy allows hedging the price risk far in the future.

### 1.1.3. Contracts for Difference

1. **Do you consider the use of two-way contracts for difference or similar arrangements as an efficient way to mitigate the impact of short-term markets on the price of electricity and to support investments in new capacity (where investments are not forthcoming on a market basis)?**

*ACER/CEER response:* Yes.

#### **Do you have additional comments?**

*ACER/CEER response:* The answer to above question is less straightforward than a simple Yes or No. ACER and CEER understand the typical two-way CfDs in question here entail (i) the state as a single buyer, (ii) settlement with single strike price (typically against the DA price) and produced volume and (iii) direct settlement with all consumers through taxes and levies (bonus or malus). These kinds of CfDs come with the opportunities as well as with risks (see Annex for detailed elaboration of these opportunities and risks).

However, ACER and CEER would have less concerns with smarter design of CfDs, which could entail the following improvements:

1. Settlement based on predefined volume or reference volume (e.g. reference wind turbine);
2. Cap and floor instead of single strike price. The floor price can replace the system of subsidies, whereas the cap price can replace the inframarginal revenue cap to channel excessive revenues back to consumers; and

3. Reselling of CfDs as financial contracts (e.g. futures) in forward markets closer to delivery (up to 3 years) and no direct settlement with consumers.

ACER and CEER call for careful design and harmonisation of design principles of such contracts (e.g. through Commission's guidelines).

Given the above, ACER and CEER at this stage cannot support EU actions mandating the use of CfDs or similar type of state long-term contracts. This is because the optimal design of CfDs is not known yet and because the Member States can achieve the objective of protecting consumers through other means as well (e.g. limit excessive inframarginal revenue, taxation policy, (energy) poverty policy, etc.). Nevertheless, Member States may be allowed to use such mechanisms to meet their objectives. In such case, this mechanism should only be implemented after a thorough assessment of negative effects on other Member States and the European electricity market and only with a State Aid approval. In case of negative effects these instruments should only be implemented if the benefits surpass cost on a European level.

**2. Should new publicly financed investments in inframarginal electricity generation be supported by way of two-way contracts for differences or similar arrangements, as a means to mitigate electricity price spikes of consumers while ensuring a minimum revenue?**

*ACER/CEER response:* Yes.

**Do you have additional comments?**

*ACER/CEER response:* The answer to above question is less straightforward than a simple Yes or No. Typical two-way CfDs in question here come with opportunities as well as with risks (see Annex for details).

However, ACER and CEER would have less concerns with smarter design of CfDs, which could entail the following improvements:

1. Settlement based on predefined volume or reference volume (e.g. reference wind turbine);
2. Cap and floor instead of single strike price. The floor price can replace the system of subsidies, whereas the cap price can replace the inframarginal revenue cap to channel excessive revenues back to consumers; and
3. Reselling of CfDs as financial contracts (e.g. futures) in forward markets closer to delivery (up to 3 years) and no direct settlement with consumers.

ACER and CEER call for careful design and harmonisation of design principles of such contracts (e.g. through Commission's guidelines).

Given the above, ACER and CEER at this stage cannot support EU actions mandating the use of CfDs or similar type of state long-term contracts. This is because the optimal design of CfDs is not known yet and because Member States can achieve the objective of protecting consumers through other means as well (e.g. limit excessive inframarginal revenue in the short term, taxation policy, (energy) poverty policy, etc.) Nevertheless, Member States may be allowed to use such mechanisms to meet their objectives. In such case, this mechanism should only be implemented after a thorough assessment of negative effects on other Member States and the European electricity market and only with a State Aid approval. In case of negative effects these instruments should only be implemented if the benefits surpass cost on a European level.

**3. What technologies should be subject to two-way contracts for differences or similar arrangements and why?**

*ACER/CEER response:* Taking into account the opportunities and risk above, wind and solar could be candidates for such arrangements. Additionally run-of-river hydro could also be covered by such arrangements. Other renewables or low-emission technologies could also be considered for CfDs.

We emphasise here the importance of designing such contracts in a way that do not distort their investment and operational efficiency.

**4. What technologies should be excluded and why?**

*ACER/CEER response:* Flexible generation such as storage, reservoir hydro, gas generation or demand response may not be suitable for such arrangements since their production volumes should be optimised based on price signals and their generation volumes and marginal costs are too uncertain to be able to adhere to such instruments.

**5. What are the main risks of requiring new publicly supported inframarginal capacity to be procured on the basis of two-way contracts for difference or similar arrangements, for example as regards of the impact in the short-term markets, competition between different technologies, or the development of market based PPAs?**

*ACER/CEER response:* As stated above we identify the following risks regarding the typical two-way CfDs:

- (a) They may have a negative impact on short term market (e.g. providing inefficient dispatch incentives such producing when prices are below their marginal costs). This could also impact investment efficiency (maximising generation output rather than market value).
- (b) They may significantly reduce the liquidity of forward markets as well as reduce the scope for competition in retail markets.
- (c) They may reduce the investment uncertainty more than necessary. It may be rational or enough to reduce only extreme uncertainty faced by investors, whereas the normal uncertainty (faced by investors in all economic sectors) should remain at investors.
- (d) Similar to RES subsidies they may lock-in the average price for consumers for very long periods (e.g. 20 years) for the volume of contracted CfDs and without taking into account consumer's preferences. It may instead be enough to only protect them against sustained periods of high prices.
- (e) Similar to the present subsidy schemes, they could lead to on average higher average prices for consumers, as the competition at CfD auctions may not achieve the level of competition experienced within integrated short-term markets (e.g. due to lack of internal competitors, no cross-border competition, high risk premia).
- (f) Central procurement of CfDs by the state may end up in inefficient outcome of over dimensioning and overinvestment of electricity system historically observed in regulated electricity systems;
- (g) As the design of state contracts may depend on specific technology, such centrally procured contracts risk making arbitrary (and possibly suboptimal) decisions on which technologies are subsidised to which extent. This may hamper incentives for innovation of other new and more efficient technologies.

As stated above some of these risks could be mitigated with smarter design of CfDs, but not all of them.

**6. What design principles could help mitigate the risks identified in question 4, in particular, in terms of procurement principles and pay out design? Should these principles depend on the technology procured?**

*ACER/CEER response:* ACER and CEER would encourage deeper analysis and investigation of all contract design options. Many design improvements have been proposed by various stakeholders and interested experts and all of these should be evaluated with the aim to achieve the desired effect and minimise their risks.

However, ACER and CEER consider that some of the risks could be mitigated with smarter design of CfDs, which could entail the following improvements:

1. Settlement based on predefined volume or reference volume (e.g. reference wind turbine);
2. Cap and floor instead of single strike price. The floor price can replace the system of subsidies, whereas the cap price can replace the inframarginal revenue cap to channel excessive revenues back to consumers;

3. Reselling of CfDs as financial contracts (e.g. futures) in forward markets closer to delivery (up to 3 years) and no direct settlement with consumers.

ACER and CEER call for careful design and harmonisation of design principles of such contracts (e.g. through Commission's guidelines).

7. **How can it be ensured that any costs or pay-out generated by two-way CfDs in high price periods are channelled back to electricity consumers? Should a default approach apply, for example, should these revenues or costs be allocated to consumers proportionally to their electricity consumption?**

*ACER/CEER response:* There are many ways how this could be achieved. It is important that settlement with consumers does not distort the incentives for demand response which is an essential condition for achieving decarbonised electricity system with currently feasible technologies. To achieve this some averaging across time would be needed. In case CfDs are resold to forward market, these benefits are channelled to consumers via suppliers buying at forward market. The design for the settlement of CfDs needs to carefully balance between protecting consumers and incentivising demand response.

8. **What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type?**

9. **Should generation be free to earn full market revenues after the CfD expires, or should new generation be subject to a lifetime pay-out obligation?**

*ACER/CEER response:* ACER and CEER prefer that any long-term arrangements supported by the state are limited in time and targeted to market gaps and failures they are aiming to address. ACER and CEER emphasise that electricity markets and price signals should remain the main drivers for investments. If state guarantees and contracts are needed to stabilise the market during decarbonisation or other crises, these should be limited to such circumstances and be phased out when markets are stabilised.

10. **Without prejudice to Article 6 of Directive (EU)2018/20016, should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity? If such possible use of regulated CfDs for existing generation is deemed appropriate, should the obligation apply to all types of existing inframarginal generation or be limited to certain types of generation (and if so, which types)?**

*ACER/CEER response:* No.

- 10.1 **If such possible use of regulated CfDs for existing generation is deemed appropriate, should the obligation apply to all types of existing inframarginal generation or be limited to certain types of generation (and if so, which types)?**

- 10.2 **Under what terms and conditions could regulated two-way CfDs on existing generation capacity be imposed?**

11. **How would you rate and address the following potential risks as regards the imposition of regulated CfDs on existing generation capacity?**

- (a) legitimate expectations/legal risks;
- (b) ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts;
- (c) locking in existing capacity at excessively high price levels determined by the current crisis situation;
- (d) impact on the efficient short-term dispatch.

12. **Would it be enough for existing generation to be subject only to a simple revenue ceiling instead of a revenue guarantee?**
13. **What are the relative merits of PPAs, CfDs and forward hedging to mitigate exposure to short-term volatility for consumers, to support investment in new capacity and to allow customers to access electricity from renewable energy at a price reflecting long run cost?**

*ACER/CEER response:* ACER and CEER see the long-term market as an equilibrium of interests of consumers and generators/investors to hedge against the uncertain future. With this respect, a liquid forward market where consumers and generators can hedge at any time any future would be an ideal market outcome. However, for various reasons such markets have not developed and instead alternatives such as PPAs and CfDs have gained momentum. Private PPAs can be seen as filling the gap of non-functioning forward markets beyond 3 years ahead, where hedging interest exists on both sides, but the organised market still has not developed enough (due to e.g. insufficient supply and demand, inadequate market design, high hedging costs). On the other hand, CfDs or other state contracts may have been developed to cover the gap between the lack of consumers' interest to enter long-term contracts (with implicit hope that the states will protect them in periods of high prices and shortages) and significant producers' interest to enter long-term contracts especially in times of high regulatory uncertainty. ACER and CEER generally support voluntary forward markets and hedging which reflect intrinsic hedging interests of market participants to cover the first gap of non-functioning forward markets beyond 3 years ahead. Regarding the second gap (different hedging interests), however, ACER and CEER suggest to leave it to the discretion to Member States on if, when and how they would provide state support. Yet, we would welcome some harmonisation of such support schemes and their review/approval subject to state aid rules.

## **1.2. Accelerating the Deployment of Renewables**

1. **Do you consider that a transmission access guarantee could be appropriate to support offshore renewables? Please explain and outline possible alternatives.**

*ACER/CEER response:* No.

**Please explain and outline possible alternatives.**

*ACER/CEER response:* ACER and CEER recognise the need for providing investment stability and certainty to offshore investors. This could be achieved through various means determined within connection agreements on a case-by-case basis. In case of offshore bidding zones, the risk of undue discrimination between market participants in onshore and offshore bidding zones is significant. Namely, within an integrated short-term market with flow-based capacity calculation, offshore bidding zones are required to compete for the capacity of critical network elements equally as any other onshore bidding zones. While most likely the offshore bidding zones would be more competitive because of zero marginal costs, it may not always be guaranteed that offshore bidding zones will get access to capacity of critical network elements due to competition. The concept of transmission access guarantee aims to address this problem; however, it may imply also a compensation paid by TSOs to offshore generators in case such access is denied due to competitive market outcome. For this reason, ACER and CEER have some reservations about the proposed transmission access guarantee. Nevertheless, ACER and CEER recognise the problem of different risks faced by offshore bidding zones compared to home market approach, whereas the latter may be compensated for curtailment due to internal congestions, whereas the former would not be. Similarly, onshore RES would have priority dispatch internally to bidding zones, whereas offshore wind would not have such right and could be dispatched only if cross-zonal capacities are available. In order to foster investments in offshore wind also in offshore bidding zones and address the above problems, other solutions than transmission access guarantee should also be investigated.

2. **Do you see any other short-term measures to accelerate the deployment of renewables?**

**(a) At national regulatory or administrative level,**

*ACER/CEER response:* Yes.

**(b) In the implementation of the current EU legislation, including by developing network codes and guidelines,**

*ACER/CEER response:* Yes.

**(c) Via changes to the current electricity market design?**

*ACER/CEER response:* Yes.

**(d) Other**

*ACER/CEER response:* Yes.

**If yes, please specify.**

*ACER/CEER response:*

National regulatory or administrative level

- Consider incorporating parts of the Commission Recommendations of 18.5.2022 on speeding up permit-granting procedures for renewable energy projects into national legislation.
- Promote regional (NUTS2) RES development plans in line with the National Energy and Climate Plans (NECPs) and align distribution system development with relevant distributed RES development targets, incorporating local storage solutions.

Implementation of the current EU legislation, including by developing network codes and guidelines

- Well-functioning short-term markets and the development of demand side flexibility are key factors to accelerate the deployment of renewables. In this sense, it is key to make progress with the enhancement of existing market codes (i.e. Capacity Allocation and Congestion Management Regulation/Forward Capacity Allocation Regulation/Electricity Balancing Regulation) and the development of new ones (e.g. demand side response).

Via changes to the current electricity market design

- Allow new RES projects to freely participate in the market.
- Optimise cross border capacity to mitigate congestion and make sure that RES generated electricity can be used as widespread as possible.

Other

- Further promote the development of renewable energy communities, citizen energy communities, active customers, renewable-self consumer mechanisms.

**3. How should the necessary investments in network infrastructure be ensured? Are changes to the current network tariffs or other regulatory instruments necessary to further ensure that the grid expansion required will take place?**

*ACER/CEER response:* Based on ACER's monitoring reports, ACER and CEER consider that the main obstacle for electricity network development is related to permitting and not to system operators' revenues and financing via network tariffs. Rather, the majority of national regulatory framework seems to offer an appropriate guarantee to system operators' investment in network development.

ACER and CEER have not yet identified financing to be a major problem in the implementation of new electricity infrastructures. However, it is reasonable to apply a socialisation of infrastructure costs across the EU (e.g. via public funds) for (i) projects in countries with tariff affordability issues, (ii) projects with financing gaps and (iii) innovative projects (e.g. electricity smart grids), under the condition that such projects are in the interest of the entire EU.

Tariff structure plays limited role in boosting infrastructure investments: The cost recovery via tariffs is secured by law, as one of the core objectives. ACER and CEER consider a gradual move to increasingly capacity-based transmission and distribution tariffs (as opposed to volumetric) as appropriate to recover those costs, which show correlation with contracted or peak capacity. More cost reflective tariffs can potentially provide better signals to network users for efficient use of the network and they can limit exposure to temporary "missing money" problem (e.g. unexpected demand drop). However, due to ex-post tariff reconciliation, the temporary missing money problem should not be a real barrier for investments. Where deep connection charges apply and the connection of a network

user serves future network users, (i.e. extending and reinforcing the network to serve one particular network user may lead to high connection costs for that user, but may ultimately reduce the connection costs to connect further users in the future), it should be considered whether cost-sharing is necessary to ensure a fair and non-discriminatory treatment of the network users, also taking into account the administrative costs for the TSOs and DSOs.

Regulatory instruments, such as incentives, may play a larger role as investments in network infrastructure are closely linked to how system operators are remunerated (e.g. benefit sharing between system operators and society) as well as to how risks are allocated among them. Regulatory incentives should provide a fair balance. However, there is no evidence indicating that the current regulatory framework (incentives) is not fit for this purpose. ACER is currently carrying out its tasks under Article 17(4) of the TEN-E Regulation which include reviewing the National Regulatory Authority (NRA) methodologies to evaluate electricity transmission investments and to evaluate their risks. This work may provide suggestions for further improvements of the national regulatory frameworks.

Regulatory instruments, like cross-border cost allocation may be helpful to deal with cases with negative benefit in a hosting country, which is a clear barrier for infrastructure investments, and which could be elevated by compensation from the benefitting countries.

### **1.3. Limiting Revenues of Inframarginal Generators**

- 1. Do you consider that some form of revenue limitation of inframarginal generators should be maintained?**

*ACER/CEER response:* No.

- 2. How do you rate a possible prolongation of the inframarginal revenue cap according to the following criteria:**

- (a) The effectiveness of the measure in terms of mitigating electricity price impacts for consumers,**

*ACER/CEER response:* 6.

- (b) Its impact on decarbonisation,**

*ACER/CEER response:* 5.

- (c) Security of supply,**

*ACER/CEER response:* 4.

- (d) Investment signals,**

*ACER/CEER response:* 4.

- (e) Legitimate expectations/legal risks,**

*ACER/CEER response:* 2.

- (f) Fossil fuel consumption,**

*ACER/CEER response:* 4.

- (g) Cross border trade intra and extra EU,**

*ACER/CEER response:* 2.

- (h) Distortion of competition in the markets,**

*ACER/CEER response:* 3.

- (i) Implementation challenges.**

*ACER/CEER response:* 3.

**Do you have additional comments?**



*ACER/CEER response:* The responses depend on the design of the solutions. Above ratings are given for the existing market revenue cap applied within EU. However, answer to point a) varies from one Member State to another based on their local generation volume (lower score for net importers).

**3. In case you consider maintaining such a revenue limitation warranted, in what situations should it apply? How should the level of the cap be defined?**

*ACER/CEER response:* While ACER and CEER are generally not supportive of this measure, we recognise that other alternatives based on long-term markets may need time to develop and that there is a potential gap and need for such a measure in the near to midterm timeframe. Hence, ACER and CEER are open to evaluate possible improvements and alternatives of such a measure with the aim to provide ex-ante certainty and visibility to all market participants on what the rules will be should a similar situation arise in near future.

There is a range of options how such revenue limitation could be implemented, among which are temporary relief valve, shock absorber or circuit breaker. All of them provide a limit on inframarginal revenue in case of sustained high prices. The benefit of these solutions is that they are limited only to extreme situations, while they have little impact on market functioning in vast majority of times. These solutions also provide predictability of market rules for future extreme situations and minimise the likelihood of unpredictable regulatory interventions. Nevertheless, this measure should not limit the incentives of the producers to maximise the generation during scarcity hours.

The measure could be applied in periods of sustained high prices with clearly defined triggering conditions. One option for the setting of caps is the multiple of levelised fixed cost for a basket of inframarginal generation technologies (i.e. when prices over certain period exceed a multiple of levelised fixed costs, then further inframarginal revenue is capped).

While a harmonised application without any room for discretionary application at national level could benefit efficiency, one-size-fits-all solutions might not always be appropriate (due to national specifics in generation landscapes and related complexity). In any case, this measure should be introduced only after a thorough assessment of positive and negative effects.

**4. Should the modalities of such revenue limitation be open to Member States or be introduced in a uniform manner across the EU?**

*ACER/CEER response:* EU.

**Do you have additional comments?**

*ACER/CEER response:* ACER and CEER would prefer that the rules for the imposition (or prohibition if that may be the case) of such revenue limitation be harmonised and applied in a uniform manner across the EU based on a predefined EU regulatory framework. This would ensure a level playing field across Member States and avoid different signals towards investors.

**5. How can it be ensured that any revenues from such limitations on inframarginal revenues are channelled back to electricity consumers? Should a default approach apply, for example, should these revenues be allocated to consumers proportionally to their electricity consumption?**

*ACER/CEER response:* Indeed, revenues from such limitations need to be channelled back to electricity consumers in one way or another (similar to RES subsidies, taxes and levies). However, this should not dampen the signal to consumers for demand response. Therefore, a hybrid solution may be advisable which protects consumers against high prices but also partly incentivises or rewards them for any demand response and energy efficiency measures.

## **1.4. Alternatives to Gas to Keep the Electricity System in Balance**

**1. Do you consider the short-term markets are functioning well in terms of:**

**(a) Accurately reflecting underlying supply/demand fundamentals,**

*ACER/CEER response:* Yes.

**(b) Encompassing sufficiently liquidity**

*ACER/CEER response:* Yes.

**(c) Ensuring a level playing field**

*ACER/CEER response:* Yes.

**(d) Efficient dispatch of generation assets**

*ACER/CEER response:* Yes.

**(e) Minimising costs for consumers**

*ACER/CEER response:* Yes.

**(f) Efficiently allocating electricity cross-border**

*ACER/CEER response:* Yes.

**2. Do you see alternatives to marginal pricing as regards the functioning of short-term markets in terms of ensuring efficient dispatch and as regards the determination of cross border flows?**

*ACER/CEER response:* No.

**Do you have additional comments?**

*ACER/CEER response:* Different pricing methods currently coexist for the different electricity market timeframes in the EU. The uniform/pay-as-cleared pricing model currently applies for the single day-ahead coupling (SDAC) market. The same pricing model will soon apply to pan-European intraday auctions. However, the pay-as-bid type of pricing model seem to be the only choice for all continuous markets (forward market and continuous intraday market).

An important remark on the debate about the pricing method is that there is often an assumption that moving from pay-as-cleared to pay-as-bid would lower the cost for consumers because low-variable-cost technologies would bid at a very low price. Such an assumption does not hold true because, in short-term markets, market participants bidding freely tend to bid at the expected market price (forecast) to be set by the marginal technology needed to supply demand at that moment in time, which would lead to inefficiencies mainly linked to the forecasting of the expected market price.

Having clarified that, there is a broad consensus that marginal pricing is, at this moment, the best available method for the auction-based markets (day-ahead market, intraday auctions) as it ensures efficient dispatch and most efficient use cross-border capacity. Regardless, marginal pricing and pay-as-bid pricing tend to result in similar prices, which represent the marginal cost of the last MW needed to satisfy the demand.

**3. How can the EU emission trading system and carbon pricing incentivize the development of low carbon flexibility and storage?**

*ACER/CEER response:* By putting a price on carbon dioxide (a measure outside of the electricity market), the EU ETS creates incentives for the power sector as a whole to reduce emissions. The carbon price signal exerts an influence across technologies and business models (including for services such as flexibility and storage) and let the market decide where and how it's most efficient to abate emissions.

The speeding up the annual emission reductions and certainty about the allowed emissions trajectory increases trust and supports the low-carbon innovation and investment. In addition, promoting long-term forward markets (beyond 5 years) for emission products would provide effective price signals to low-carbon investments.

With the increasing share of variable renewables, flexibility in the power system is becoming ever more important. At the same time, currently, flexibility is mostly provided by fossil generators or reservoir

hydro while demand response and other storage technology is only starting to become available at a wide commercial scale. Driven by market demand, the development of low-carbon flexibility, demand response and storage are expected to develop fast as effective carbon price signals place them on equal footing with the more polluting competition.

The development of low carbon flexibility and storage could also be further incentivised by allocating more ETS revenue into these investments. At the same time, any such potential incentive scheme must be designed in a way so it does not unduly distort competition between low-carbon investments.

**4. Do you consider that the cross-border intraday gate closure time should be moved closer to real time (e.g. 15 minutes before real time)?**

*ACER/CEER response:* The question of shortening the intraday cross-zonal gate closure time raises complex issues linked to system operation (namely balancing and congestion management) closer to real time. Moving the gate closure nearer to real time may require Transmission System Operators (TSOs) to perform balancing and real-time congestion management in parallel to intraday markets. This may be difficult for some TSOs and could require a shift in the system operation paradigm. Nevertheless, as outlined in our reflection paper on offshore bidding zones, EU regulators identified that it may be beneficial to move the intraday cross-zonal gate closure time closer to real time at least for the following two cases:

- (a) for all offshore interconnectors,
- (b) in case the intraday cross-zonal gate closure time is earlier than the intraday internal gate closure time (the two should be equal to avoid discrimination between internal and cross-zonal exchanges).

However, moving the intraday gate closure time in all bidding zones and bidding zone border requires a deeper analysis of feasibility with regard to the needed operational actions by the TSOs in a short period of time and the costs/benefits of such a change. The benefits of such a change would also be conditioned to the actual availability of cross-border capacity up to real time. There would be little benefit in requiring shorter gate closure times if the cross-zonal capacities for cross-border trade close to real time is very low or zero.

**5. Do you consider that market operators should share their liquidity also for local markets that close after the cross-border intraday market?**

*ACER/CEER response:* Yes.

**What would be the advantages and drawbacks?**

*ACER/CEER response:* The current Single intraday coupling (SIDC) is built on the model where market operators (NEMOs) share their liquidity into a single Shared Order Book (SOB). Based on the cross-zonal capacity made available to the SOB, market participants from individual NEMOs can thereby trade continuously between them across all NEMOs and across all EU bidding zones.

Currently the trade between NEMOs active in the same bidding zones does not continue after the cross zonal gate closure time (an hour before the delivery). As the intraday (ID) market in the final hour before real time is the most liquid and relevant for market participants to compete in, the sharing of liquidity in the final hour, after the cross zonal trade is closed, is important to increase competition between market participants and allow equal access to liquidity to the market participants from different NEMOs active in the same bidding zone. As the final hour of ID trade is most liquid part of the ID timeframe, not sharing the liquidity in this period also negatively impacts the competitive position of NEMOs prior to the cross zonal gate closure time. Therefore sharing liquidity would benefit both the level playing field of NEMOs operating and of market participants active on SIDC.

**6. Would a mandatory participation in the day-ahead market (notably for generation under CfDs and/or PPA's) be an improvement compared to the current situation? What would be the advantages and drawbacks of such approach?**

*ACER/CEER response:* The question of whether participation in day-ahead markets should be mandatory or not was extensively discussed in earlier market reforms. Currently, there is a broad consensus that freedom to choose trading venues is an important part of a free and efficient electricity

market. Nevertheless, efficient markets require transparency of price signals and other fundamental information and for this reason it is important that a large portion of trading is done through organised marketplaces which can facilitate efficient trade and provide efficient price signals.

Currently, participation in the organised marketplaces such as day-ahead market is a choice of each Member States and some of them have chosen to apply such requirement.

On the one hand, mandatory participation entails some advantages, e.g. a higher level of transparency, e.g. because bids and offers can be more easily monitored. On the other hand, mandatory participation may present a number of drawbacks, e.g. it may distort market participants' choices and bidding behaviour.

Finally, the mandatory participation of generation specifically procured under CfDs or PPAs may pursue other goals. For example, it may aim at ensuring that all consumers benefit from stable prices settled in centrally organised tenders, e.g. those organised by governments to procure renewable energy. However, mandatory participation is not needed to achieve this objective; ensuring that the entity organising the tender redistributes the savings among consumers would be enough.

In case of state procured CfDs settled against the day-ahead price, the generators are automatically incentivised to participate in the day-ahead market as this minimises their risk. The possible danger of PPAs with physical delivery is that the volume of trading in day-ahead market decreases below the minimum volume required for transparent and efficient price signals. In such case, it may be justified to require participation at the day-ahead market.

With the emergence of financial (as opposed to physical) CfDs and PPAs, the question on the mandatory participation in day-ahead markets for generation under these schemes (CfDs/PPAs) seems to be decreasingly relevant. If those schemes are adequately designed, market participants would be incentivised to participate in the day-ahead markets even without explicit obligations.

In sum, ACER and CEER do not yet see the need to impose mandatory participation in the day-ahead market in the current situation.

## **7. What would be the advantages and drawbacks of having further locational and technology-based information in the bidding in the market (for example through information on the composition of portfolio, technology-portfolio bidding or unit-based bidding)?**

*ACER/CEER response:* In the recent market design debate the bidding on individual unit level, linked to their technology/resource type, has been extensively discussed.

One advantage of unit-level bidding would be that it provides more transparency on individual bids per individual generation units making regulatory oversight easier and allowing to assess better the efficiency of price formation and market design changes. It may also reduce gaming in case of locational market power due to predictable congestions and redispatching. Another advantage is more accurate information of TSOs on unit scheduling which helps the accuracy of network modelling. It also allows market participants to more easily represent the asset capability in their bids (assuming that algorithms allow such flexibilities).

On the other side, the drawbacks of such an approach would be that it could limit free price formation (enshrined in Article 3 of the Electricity Regulation) because the standard product specification and algorithm functionalities may not enable optimisations that are possible under portfolio bidding (it is to note that portfolio bidding does not restrict the freedom of unit bidding, whereas unit bidding does restricts the freedom of portfolio bidding). Also, full unit bidding would not even be possible as distributed energy resources and demand response need aggregation at least at nodal level to participate at wholesale market. Unit bidding would also have an impact on market-coupling algorithms, which currently are disproportionately burdened by orders coming from markets with unit bidding compared to orders from markets with portfolio bidding.

In sum, ACER and CEER suggest an approach where a portfolio bidding and optimisation would be allowed at least at a nodal (transmission) level, while leaving the requirement for unit bidding for bigger generation units to the Member State's discretion.

**8. What further aspects of the market design could enhance the development of flexibility assets such as demand response and energy storage?**

*ACER/CEER response:* The main barrier to access for demand response and storage seems to be the clear absence of a common market design providing a level playing field between all market participants (existing and new). The currently mandated framework from the Electricity Directive provides for nationally defined framework which depend on calculated settlements between existing and new market participants. These (national) frameworks usually entail a long regulatory process to get this implemented. A common framework where each market participant is allowed access to the market and is settled based on metering or submetering would provide for a level playing field and proper allocation of costs and benefits.

**9. In particular, do you think that a stronger role of OPEX in the system operator's remuneration will incentivize the use of demand response, energy storage and other flexibility assets?**

*ACER/CEER response:* No.

**Do you have additional comments?**

*ACER/CEER response:* Proper remuneration of OPEX would not be sufficient to incentivise demand response. TSOs should have no problems using DSR once it becomes widely available. Other incentives can be much more successful in stimulating DSR, storage and other flexibility assets, compared to overcoming the CAPEX bias (which may play a stronger role in limiting low-cost investments, e.g. smart grids). Despite a limited impact on flexibility, a TOTEX approach should, in most cases, be favoured (in contrast to CAPEX remuneration and OPEX pass-through).

**10. Do you consider that enabling the use of sub-meter data, including private sub-meter data, for settlement/billing and observability of demand response and energy storage can support the development of demand response and energy storage?**

*ACER/CEER response:* Yes.

**Do you have additional comments?**

*ACER/CEER response:* Submetering could allow proper competition behind the main meter and would ensure proper allocation of costs revenues between suppliers/aggregators and consumers linked to actual provision of services without the need for aggregation models that have to depend on assumptions due to the absence of metering devices for settlement. A main barrier to this development is the very limiting requirements in the Metering Directive (for instance requiring every (sub) meter to have a display showing the measurement). It should also be noted that some mandatory calibration requirements for metering equipment may add complexity to this topic.

**11. Do you consider appropriate to enable a product to foster demand reduction and shift energy at peak times as an ancillary service, aiming at lowering fuel consumption and reducing the prices?**

*ACER/CEER response:* No.

**Do you have additional comments?**

*ACER/CEER response:* Demand response should be a product developed by market participants and between wholesale market actors and (retail) consumers. Requiring further ancillary services to be procured by system operators to reduce demand would provide a barrier to this development in the market. Proper price incentives for market participants and access of (retail) consumers to such services should be enough to develop these services in the market.

Apart from being against such newly developed ancillary service, it is clear that barriers to the current ancillary services procured (like balancing, congestion management and voltage control) need to be further reduced to allow more participation for demand response and storage. For references, please refer to ACER's Framework Guidelines on Demand Response.

**12. Do you consider that some form of demand response requirements that would apply in periods of crisis should be introduced into the Electricity Regulation?**

*ACER/CEER response:* No.

**Do you have additional comments?**

In principle, demand response should be an integral part of the market itself. The priority therefore should be to remove any barriers for demand response and properly implement the Electricity Directive and Regulation across Europe. In the meantime, dedicated requirements for demand response could be implemented where the demand-side faces significant barriers for participating in the wholesale markets and there is a need to kick-start its development.

Prior to introducing any specific requirements for demand response at times of crisis, it would be important to evaluate the reaction of the demand-side to the energy crisis and effectiveness of dedicated demand response measures developed in the context of the EU's emergency regulation. Early evidence suggests that the demand side has responded strongly to the high electricity prices and played its part in keeping power prices lower than otherwise would have been the case, and ensuring the reliable operation of the power system. This early evidence suggests that the demand-side is not as inelastic as often thought. This is before any dedicated requirements for demand response.

**13. Do you see any further measure that could be implemented in the shorter term to incentivize the use of demand response, energy storage and other flexibility assets? If so, what would that be?**

*ACER/CEER response:* No.

**14. Do you consider the current setup for capacity mechanisms adequate to respond to the investment needs as regards firm capacity, in particular to better support the uptake of storage and demand side response? If not, what changes would you consider necessary in the market design to ensure the necessary investments to complement rising shares of renewables and to better align with the decarbonisation targets?**

*ACER/CEER response:* Yes.

**Do you have additional comments?**

*ACER/CEER response:* The European adequacy framework rests on two basic pillars (i) a common European approach to assess adequacy risks (ERAA Methodology) and (ii) national capacity mechanisms (CMs) to eliminate the risks identified.

- (i) While the ERAA Methodology provides an appropriate approach for a coordinated assessment both on a European and national level, it is not yet fully rolled-out. Hence, the focus should be on strengthening the implementation efforts to get to a clear and consistent picture of adequacy needs.
- (ii) CMs, if well designed, are capable of eliminating identified adequacy concerns, at least on a temporary basis, until market failures are corrected. The focus should be on refining design principles by incorporating lessons learned from implementation experiences and to a certain degree harmonising design details to better mobilise European resources.

While the single European resource adequacy assessment – once fully implemented – provides a solid basis for a level playing field, the wide variety of national CM designs form a barrier to share resources cross-border and achieve a higher security of supply level overall.

The patchwork of different CMs aiming to ensure national resource adequacy cannot fully exploit the benefits offered by a wider interconnected network, including the benefits from cross-border competition. While cross-border participation in national CMs is required, the implementation experience shows that it is very complex and does not deliver an efficient market outcome.

A relevant reason for the slow progress in cross-border participation is the wide range of design solutions applied in national CMs which results in the need to conclude ad-hoc inter-TSO agreements.

In conclusion, while CM design details should be able to fit the situation of a particular Member State (e.g. national electricity systems and reliability standards) there is scope for further harmonisation to better exploit resources from a wider geographic area. Such harmonisation elements should also e.g. mitigate the risks of over-dimensioning and market power. In addition, further harmonisation of CM designs could promote a more streamlined implementation process.

The current adequacy framework can accommodate CMs designs that incentivise flexible and decarbonised resources. Entrusting CMs to deliver on manifest policy targets other than resource adequacy, without also harmonizing their design, risks adding more complexity (e.g. derating factors) and further fragmenting the landscape. Specific policy targets are best tackled with specific EU framework such as EU ETS driving decarbonisation in a technology neutral way.

**15. Do you see a benefit in a long-term shift of the European electricity market to more granular locational pricing?**

*ACER/CEER response:* Yes.

**Do you have additional comments?**

*ACER/CEER response:* The objective of the current European electricity market design is to adequately reflect the physical reality of the transmission network, while also allowing freedom to trade without constraints within the respective bidding zone. A more granular and adequate configuration of bidding zones is important to bring market and system operation of the network closer together and to incentivise efficient operational and investment decisions for both supply, demand and network. A more locational pricing through adequate bidding zones would provide incentives for higher renewables penetration, energy-intensive demand and would help identify the most valuable network investments.

In Continental Europe, the idea of more granular bidding zones evokes concerns about forward market liquidity. Yet most electricity markets in the world have addressed this concern by pooling liquidity in larger trading hubs across multiple bidding zones or nodes. This is the concept suggested in another section of this consultation and would be a way of address these concerns.

Another concern relates to the coexistence of different DA electricity prices within a given Member State, sometimes perceived as contentious or socially unfair (note that these differences also occur also due to other tariffs, taxes or levies). Such differences may be mitigated by national retail or tariff/tax policies, although it may be advisable to preserve these differences in order to maintain investment signals and incentives for both generation and consumption as well as reduce public opposition to investments in transmission.

A more systematic approach to more locational pricing is the implementation of the so-called nodal pricing where electricity markets would have zones equal to transmission nodes that would have individual prices. The benefits from implementing nodal pricing are similar in nature to those from a better bidding zone configuration, but possibly much larger in magnitude. Additionally, nodal pricing would resolve the difficult task of agreeing on an “adequate” configuration of bidding zones. In turn, implementing nodal pricing would require substantial regulatory changes and a long implementation process. However, it would solve some of the existing problems like avoiding the complex and often discriminatory capacity calculation methodologies and complex regional remedial action coordination and associated cost sharing.

In sum, more granular locational pricing has the potential of supporting an efficient energy transition. More granular pricing is currently possible without market design changes, but it would likely require broad political consensus. In the longer-term, implementing nodal pricing at EU level could be considered and discussions in this direction are welcomed. However, it is important that not all hopes are put into such long-term objectives and promises and that existing objectives of better configuration of bidding zones and implementation of minimum capacity requirements (70% targets) are implemented first.

## 1.5. Better Consumer Empowerment and Protection

### 1.5.1. Energy Sharing and Demand Response

#### 1. Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?

*ACER/CEER response:* Yes.

##### Do you have additional comments?

*ACER/CEER response:* Energy sharing can be done efficiently only if smart meter infrastructure is operational and network tariffs/levies are not netted, in order to avoid cross-subsidisation among groups of customers (i.e. customers that do not share would pay higher network costs). In order to avoid complexities in settlement, withdrawals and injections should happen in the same hour. Cross-zonal energy sharing would be far more complex considering network constraints among different zones, in particular in some countries where network constraints are stringent, while cross-border sharing would become even more complex considering that two different jurisdictions would be involved. Offsite generation deduction opens the field of possibilities for generation sites and incentivises investment. One could argue that there are already useful provisions in the EU 2019/944 Directive, that these are being implemented and that it is necessary to give time for proper implementation and allow for proper evaluation and feedback.

#### 2. If such a right were introduced:

##### (a) Would it affect the location of new renewable generation facilities?

*ACER/CEER response:* No.

##### Do you have additional comments?

*ACER/CEER response:* The decision on the location should not be dependent on considerations other than network capacity, availability and suitability of preproduction-related factors. One should avoid creating the conditions for gaming and ensure that network costs continue to be covered in a cost-reflective way. Energy sharing may at least open the realm of possibilities and give another incentive, especially for SMEs, industries, municipalities and communities.

The deduction of offsite generation should not affect the location of new renewable generation facilities if network costs are included in the “calculation”.

##### (b) Should it be restricted to local areas?

*ACER/CEER response:* Yes.

##### If yes, why?

*ACER/CEER response:* A legal and technical definition of “local areas” can be difficult. Provided that consumption and generation occur at the same time or are measured on the same time frame (at least hourly if not quarter-hourly), energy sharing can be promoted, so long as network costs are covered in a cost reflective way and do not generate a disproportionate amount of complexity and treatment costs. All options should be left open and studied to determine under which circumstances offsite generation deduction would be suitable and when it could effectively be proposed to the market participants.

One could argue that it could be promoted locally in the first instance, to capture low-hanging fruits, and later expanded, where it makes sense, as long as the benefits outweigh the costs and complexity of implementation. For example, energy sharing within a control zone is a very different task from sharing across different control zones with significant differences and challenges when it comes to the complexity of implementation. The scale of energy sharing should be evaluated considering the ease and the horizon of implementation considering, network capacity, markets, etc. If at a later date, network costs can be netted between areas and not result in cost implications for all consumers then sharing outside of local areas could potentially be considered.



**(c) Should it apply across the Member State/control/zone – why and what should happen if bidding zones are changed?**

*ACER/CEER response:* No.

**Do you have additional comments?**

*ACER/CEER response:* In theory, everything is possible, but the suitable geographical scale depends on a variety of considerations. The benefits should outweigh the costs and complexity of implementation. The scale of application should be assessed with regard to objective principles regarding, among others, the actual level of interoperability and the availability of capacity. Moreover, the scale of energy sharing should be evaluated considering the horizon of implementation, allowing for proper evaluation and feedback.

**3. Would you support establishing a right for customers to a second meter/sub-meter on their premises to distinguish the electricity consumed or produced by different devices? If yes, what particular issues should be taken into account?**

*ACER/CEER response:* Yes.

**If yes, what particular issues should be taken into account?**

*ACER/CEER response:* Granting a right implies an obligation, and maybe goes too far too soon. Please see instead terminology on “enabling” sub-meters in the alternatives to gas section (Q10).

Sub-metering has the potential to foster proper competition coupled with the main (smart) meter provided by the DSO, by ensuring proper allocation of costs and revenues between suppliers/aggregators and consumers. This model enables a proper reflection of the actual cost of the provision of services without the need for aggregation models reliant on assumptions, due to the absence of metering devices for settlement. The main barrier to this development is the very limiting requirements in the Metering Directive (for instance requiring every (sub) meter to have a display showing the measurement). It should also be noted that some mandatory calibration requirements for metering equipment may add complexity to this topic.

Enabling the option or even granting a right to sub-metering should not imply socialisation of the costs and should stay true to the prerequisite of cost reflectivity. The costs related to sub-metering should be borne by the customer.

One should consider enabling the possibility of sub-metering development, having in mind that any barriers to entry must be avoided and allow the market to develop as long as it does not jeopardise system security and cybersecurity, in particular.

Moreover, this topic has to be further studied in accordance with ACER’s Framework Guideline on Demand Response.

There is also a need for standardisation of the data requirements and of the potential submetering equipment.

Standardisation in submeters, standardisation of data used for market purposes, have some minimum requirements, pass a quality check-list or prequalification process.

One could argue that there are already useful provisions in the EU 2019/944 Directive, that these are being implemented and that it is necessary to give time for proper implementation and allow for proper evaluation and feedback.

## **1.5.2. Offers and Contracts**

**1. Would you support provisions requiring suppliers to offer fixed price fixed term contracts (i.e. which they cannot amend) for households?**

**2. If such an obligation were implemented what should the minimum fixed term be?**

**(a) Less than one year,**

**(b) One year,**

- (c) Longer than one year,
- (d) Other.

*ACER/CEER response:* Other.

**If 'other', please specify,**

*ACER/CEER response:* There are a wide variety of contract periods currently available across Europe, which can range anywhere from 3 months to 5 years, for example. With this in mind, it is difficult to set an EU-wide minimum fixed-term contract duration. EU-wide evidence is not currently available regarding the impact of contract duration on retail prices or consumer choice. If an obligation on fixed price fixed term offers were introduced, it should be voluntary to implement the provisions and up to each Member State to set a minimum fixed term.

### **3. Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts.**

#### **(a) Should these provisions be clarified?**

*ACER/CEER response:* Yes.

#### **(b) If these provisions are clarified, should national regulatory authorities establish ex ante approved termination fees?**

*ACER/CEER response:* No.

#### **Do you have additional comments?**

*ACER/CEER response:* It is difficult to set ex ante termination fees for fixed price, fixed term contracts. Different suppliers have different costs. With ex-ante fees, some customers will pay too much, others too little, and very few will pay an exact, cost-reflective price.

The cost-reflectiveness of termination fees has to be tested case-by-case and ex-post. However, regulation could be clarified, with guiding principles that suppliers can use when setting the fees and NRAs can use when monitoring the fees, including for example in terms of defining “direct economic loss” and “proportionality”. These would promote transparency, trust and accountability by suppliers. Guiding principles could be:

- A termination fee must be proportionate and take into account, for example, the remaining contract duration, the calculated remaining volume and market price for electricity or expected gain for the supplier or aggregator. Any persisting hedging costs would be taken into account in the assessment of the direct economic loss resulting from the customer’s early departure.
- A termination fee cannot be used to benefit the supplier or the aggregator economically, it can only be used to cut losses. If there is no economic loss, there should be no termination fee.
- Suppliers or aggregators are obliged to inform customers about the calculation method used to determine the termination fee upfront and in the contract (not only in the fine print). Further, suppliers must be able to inform customers how the termination fee has been calculated upon request. This helps customers, customer advisories and monitoring authorities.

### **4. Do you see scope for a clarification and possible stronger enforcement of consumer rights in relation to electricity?**

*ACER/CEER response:* Yes.

### **5. What should be done to clarify consumer rights and ensure stronger enforcement?**

*ACER/CEER response:* Consumers are often unaware of actual contractual terms and prices. Suppliers should **clearly, regularly and timely communicate** key conditions (Art 10) and any changes to prices and end dates of contracts in mandatory standardised way, using a range of communication methods. This is even more important if terms or prices change infrequently, i.e. biannually, annually or irregular, or contracts with longer durations.

In case of **full/partial orderly market exit** by suppliers, there should be clear and aligned rules, processes, and communication requirements to ensure continuous supply to consumers. These rules

should include sufficient notice periods to affected customers and market actors, including NRAs. Information regarding exit procedures, options and instructions for customers must be clearly communicated and could consider using media advertisements. In case of customer acquisition by a successor, new contract information needs to be communicated and alternatives presented in advance.

Despite existing rights requiring a **good standard of service and complaint handling** by suppliers, no framework exists to evaluate and ensure compliance, making comparisons of service quality by consumers impossible. Derived from already existing supplier obligations, shared minimum standards of good service and complaints by suppliers ensure consumers reap market benefits beyond price. NRAs should assess compliance using, for instance, monitoring tools or licensing to strengthen enforcement of essential consumer rights. Also, NRAs should have oversight of consumer complaints and maintain a register of complaints submitted by consumers regarding their energy supply.

New protection provisions in the **Gas Decarbonisation Package** should also be considered for electricity, where applicable.

### **1.5.3. Prudential Supplier Obligations**

#### **1. Would you support the establishment of prudential obligations on suppliers to ensure they are adequately hedged?**

*ACER/CEER response:* Yes.

#### **Do you have additional comments?**

*ACER/CEER response:* Member States should be allowed to impose such obligations at national level if they can find ways to mitigate risks described in our responses to Q4 and Q4.1. under “PPA” and the “Forward markets” sections. Additionally, we highlight the following advantages and risks at retail level.

#### Advantages:

Hedging limits suppliers’ exposure to price increases and thus lowers their risk of bankruptcy, which can protect consumers from sudden price increases and contract terminations. Hedging also ensures some predictability regarding energy bills. Hedging aims to ensure that suppliers act in a more financially responsible manner and take steps to bear an appropriate share of risk. Adequate hedging would prevent the socialisation of costs (through Supplier of Last Resort (SOLR)) in case of a supplier failure.

One option worth assessing is for prudential obligations to extend also to market entry requirements (in the framework of minimum capital or licencing requirements where applicable, e.g., in NL, PL). Another option is to ensure that the supplier hedges a certain volume of e.g., fixed-price and fixed-term contracts, in advance. However, the level of termination fees must be considered in these cases.

#### Risks:

However, the sourcing of hedging for suppliers represents a significant cost burden which may make it difficult for suppliers to offer fixed-price energy contracts and can create market entry barriers e.g., to newcomers and innovative business models. Therefore, such additional costs would be passed to the consumer, which could make such contracts less attractive.

Also, this sort of obligation would constitute an intervention and would heavily impact commercial strategies and freedom of suppliers, which in turn might negatively impact competition.

Further, supervision and setting the “adequate” level of hedging is a complex task and can negatively impact the free price setting on the market.

Lastly, hedging might not fully protect suppliers in case of supply shocks, or customers in case of supplier failure.

#### **2. Would such supplier obligations need to be differentiated for small suppliers and energy communities. If Yes/No, why (not)?**

### 1.5.4. Supplier or Last Resort

#### 1. Should the responsibilities of a supplier of last resort be specified at EU level including to ensure that there are clear rules for consumers returning back to the market?

*ACER/CEER response:* Yes.

##### **Do you have additional comments?**

*ACER/CEER response:* Electricity Directive provisions (Art. 27) on the right to universal service and the possibility for Member States (MSs) to establish SOLR are in force in almost all MSs but implementation varies widely (scope, designation procedures, NRA role, price setting mechanism, contractual conditions) while price levels are higher than average prices in almost all countries.

During the crisis, SOLR processes underwent a “stress test”, revealing some limitations. All customers were at risk of losing the right of universal service (public institutions, schools, large industry). Customers suffered from even higher prices and uncertainties of procedural and timing aspects of SOLR services besides widespread reluctance of suppliers towards greater customer acquisition during critical circumstances. In some cases, in which SOLR were selected with auctions, these either went deserted or were allocated with very high prices. In other instances, the appointed SOLR in turn went bankrupt, meaning those consumers were transferred to another SOLR.

Regulators believe that a minimum common definition of the nature, scope and role of SOLR needs to be identified. SOLR should not compete with other market suppliers and its conditions should be price transparent, cost reflective and where possible hedged. An obligation for MS to establish, with transparent procedures, SOLR offering at a reasonable administrative price universal service, preferably to all customers should be set into legislation. SOLR should be in any case granted for vulnerable, not interruptible and domestic customers and where MS consider it necessary extended to other customers. NRAs should have a role in regulating SOLR service (transparent pricing principles, quality of service, customer rights). SOLR should be required to inform customers clearly and promptly when they are onboarded of all key contractual and price conditions for electricity supply and their right to switch to another supplier within the standard switching time.

#### 2. Would you support including an emergency framework for below cost regulated prices along the lines of the Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices, i.e. for households and SMEs?

*ACER/CEER response:* No.

##### **(a) If such a provision were established, price regulation should be limited in time and to essential energy needs only?**

*ACER/CEER response:* Yes.

##### **(b) Would such provisions substitute on long term basis for direct access to renewable energy or for energy efficiency?**

##### **(c) Can this be mitigated?**

##### **(d) Would such contracts reduce incentives to reduce consumption at peak times?**

*ACER/CEER response:* Yes.

##### **(e) Can this be mitigated?**

*ACER/CEER response:* Yes.

##### **Do you have additional comments?**

*ACER/CEER response:* In normal circumstances, well-functioning markets and effective competition are best placed to deliver the best outcomes for the system and customers. In a crisis, social policy and other means should be targeted to support specific consumer groups, such as those in situations of vulnerability or energy poverty, rather than via catch-all measures. The proposals on hedging obligations, PPAs, CfDs, etc. to make bills more independent from price fluctuations, should help mitigate risks of extreme high prices or crises in future.

Any provision for emergency situations would need to establish clear, strict criteria for below cost prices, as these can damage retail competition and harm consumer welfare. The conditions for a “crisis” would need to be clearly defined and verifiable, with a clear process and timeline to phase them out set in advance. Their application must be time-limited and applicable only to essential energy needs, retaining a price component to encourage efficient energy use/reduction, especially at peak times. Price signals are essential to influence consumer behaviour. Also, the measure must not jeopardise the financial sustainability and stability of the system or suppliers. The conditions established in Regulation 2022/1854 must be strictly fulfilled, including supplier compensation. The measure should also be limited to energy poor, or vulnerable households and SMEs.

To avoid the need to use this exceptional measure, MSs should be incentivised to prioritise other market or social instruments to safeguard against the emergence of such crises (e.g. hedging obligations for suppliers, including the supplier of last resort; social support instruments for consumers; reductions in network tariffs...).

## **1.6. Enhance the Integrity and Transparency of the Energy Market**

### **1. What improvements into the REMIT framework do you consider as most important to be addressed immediately?**

*ACER/CEER response:*

#### Harmonising the REMIT legal framework with the EU financial market legal framework

REMIT would benefit from a better alignment with the framework existing under the financial legislation, which significantly evolved over the last decade. Certain elements of the definitions of inside information and market abuse should be better aligned between REMIT and MAR. Similarly, the definitions of OMP and OTC should be aligned between REMIT and other EU financial market legislation. The inclusion of specific rule examples for market manipulation and insider trading on energy wholesale markets (as in MAR), would be highly beneficial in terms of enforcement and legal certainty for the market.

Furthermore, ACER’s powers under REMIT should also be, where appropriate, aligned with ESMA’s powers under the EU financial market legislation. This includes the possibility for ACER to develop draft implementing technical standards for the Commission, in cases where power is conferred upon the Commission to adopt implementing acts, similarly to ESMA’s powers under EU financial market legislation. This would allow for more frequent updates of the REMIT implementing acts pursuant to Article 8 of REMIT, in order to keep up with evolving markets and developments in EU financial and energy market legislation.

The compliance with the reporting obligations under REMIT could also be improved by granting ACER the task to supervise at EU level the respect of the reporting obligations under Article 8 of REMIT. More specifically, ACER could be assigned the mandate to supervise reporting entities (registered reporting mechanisms) with the possibility to adopt administrative sanctions and other administrative measures for potential breaches of the REMIT reporting obligation defined in Article 8 of REMIT (similarly to ESMA’s powers under Articles 78 and following of the EMIR regulation).

#### Adapting the scope of REMIT to current and evolving market circumstances

REMIT and its Implementing Regulation (EU No 1348/2014) should cover all the markets/ products referred to in the EU electricity and gas legal frameworks (current and future). They should also be revised to explicitly cover in their scope the order book providers such as the operators of the single day-ahead market coupling, the intraday market coupling and the EU Balancing platforms. These order book providers should be fully subject to the reporting obligations under Article 8 of REMIT, and the reporting should happen in a consolidated manner at EU level. They should also be considered as persons professionally arranging transactions subject to the obligation to monitor their market and report potential breaches of REMIT in accordance with Article 15 of REMIT.

The increasing share of financial instruments traded on EU energy markets also calls for a reconsideration of the scope of REMIT. According to REMIT, derivatives on energy commodities are wholesale energy products reportable to ACER. ACER receives trading data on energy commodity derivatives and fundamental data that enables the monitoring of abusive behaviours in these market

segments. ACER thus performs its mission to monitor the EU wholesale energy markets both on spot/physical forward products and on derivatives on commodities. Yet, the prohibitions of market abuse (insider trading and market manipulation) under REMIT do not apply to commodity derivatives which are also financial instruments and to which the MAR regulation applies (Article 1(3) of REMIT). Considering the existing interlinks in terms of market impact between spot and derivative wholesale energy products, energy regulators should be competent to apply the prohibitions of insider trading and market manipulation to derivatives on energy commodities. The derivatives on energy commodities should remain financial instruments covered, where applicable, by MiFID II, but the reduction of the scope of REMIT currently included in its Article 1(3) should be removed.

## **2. With regards to the harmonization and strengthening of the enforcement regime under REMIT: what shortcomings do you see in the existing REMIT framework and what elements could be improved and how?**

*ACER/CEER response:*

### Convergence of the levels of fines imposed under REMIT at national level

REMIT established that by 29 June 2013, each Member State should ensure that its NRAs have the investigatory and enforcement powers necessary for the implementation of the prohibitions against market abuse. This implementation of REMIT at national level resulted in different regimes and powers given in each Member State to the NRAs. This visibly resulted in major discrepancies among Member States as to the level of the fines that NRAs can issue as a sanction. Having converging levels of fines throughout the European Union is an important element of their deterrence and of the efficient implementation of the REMIT framework. To this end, REMIT should provide a minimum threshold (a percentage of the total annual turnover) for the level of the maximum administrative fines imposed at national level by NRAs, per type of REMIT breach (drawing on what exists under MAR and competition law).

### Strengthening the enforcement regime under REMIT

REMIT provides for the cooperation between ACER, NRAs, ESMA, competent financial authorities of the Member States and national competition authorities. The enforcement of REMIT would benefit from an extension of this list to include tax authorities, the EUROFISC group, as well as the European Commission. REMIT should also explicitly provide for the possibility for these listed authorities to exchange information and data. A direct communication line between energy and tax authorities would enable energy regulators to more easily report tax related behaviours, such as VAT frauds, that may involve wholesale energy products. This is key to prevent such unwanted behaviours from occurring on the EU wholesale energy markets and better preserve their integrity. In a similar way, ACER should be able to cooperate and exchange information/data with the services of the European Commission, and notably DG Competition on scrutinised behaviours that may constitute a breach of competition law. Moreover, ACER and NRAs should be able to develop cooperation mechanisms with third countries' authorities specifically allowing for the exchange of REMIT information under the following double condition: reciprocity and same level of professional secrecy imposed on agents of the respective authorities.

Reinforcing the monitoring role of persons professionally arranging transactions (PPATs) would also contribute to a better enforcement of REMIT. Article 15 of REMIT provides that PPATs who reasonably suspect that a transaction might breach Article 3 or 5 of REMIT shall notify the NRA without further delay. This provision should be enlarged to capture also orders (as opposed to focusing on transactions), and to possible breaches of the obligation to disclose inside information under Article 4 of REMIT (instead of being limited to the detection of market abuse under Article 3 or 5 of REMIT). Lastly, since the Agency is in charge of the monitoring of the EU wholesale energy markets, it should, alongside the NRAs, be the recipient of the PPATs' notifications under Article 15.

To avoid jurisdictional issues, market participants from third countries should be required to declare a registered office in the EU (as in the EU financial market legislation).

Finally, market abuse cases involving multiple cross-border elements and market participants not established in the EU can represent a challenge for the enforcement of REMIT. The REMIT framework would benefit from allowing NRAs to rely more on ACER in these cases.

**3. With regards to better REMIT data quality, reporting, transparency and monitoring, what shortcomings do you see in the existing REMIT framework and what elements could be improved and how?**

*ACER/CEER response:*

REMIT reporting and data quality

A centralised reporting regime to ACER at Union level requires granting ACER supervisory powers over RRM to improve data quality and to ensure a level playing field between RRM. This would enhance the quality of the data that ACER and NRAs receive and use to fulfil their respective mandates of monitoring the EU wholesale energy markets. Under the current REMIT framework, ACER's supervisory powers over RRM are very limited and should be further developed. ESMA's supervisory powers over reporting entities under the transaction reporting regimes under MiFIR and EMIR can serve as a role model.

The current reporting regime, under which market participants may choose to report Organised Market Place (OMP) data through other channels, causes fragmentation and significant data quality issues and hinders effective market monitoring. Market participants should be required to report all OMP data through the OMP where the trading occurs, while OMPs may still choose third party RRM to report the data to the Agency. However, to avoid disproportionate reporting costs imposed by RRM on the market participants, ACER should be in charge of supervising and assessing the fairness of the applied reporting costs, similarly to the competences of ESMA vis-à-vis trade repositories under EMIR.

Transparency

EU wholesale energy markets would greatly benefit from a more streamlined mandatory disclosure of inside information by market participants through platforms, also indirectly with the support of System Operators when the inside information relates to the capacity and use of facilities. REMIT should provide for the mandatory disclosure of inside information through dedicated inside information platforms. This would have the benefit of reducing the number of locations market participants have to turn themselves to in order to access inside information. . In order to ensure a level playing field of inside information platforms at EU level and their continuous reliability, ACER should have supervisory powers over them and assess their compliance with relevant technical standards to which these platforms should adhere.

Monitoring

In order to facilitate monitoring to detect potential trading based on inside information, the collection of inside information needs to be aligned with the current process for trade data reporting. ACER is currently pulling the data through webfeeds, but it should be pushed to ACER in the same way as trade data. This would also facilitate data sharing.

There is also a need to overcome potential gaps in the data collection of coupled markets. The current definition of OMP, as laid down in the REMIT IR, is not in line with the evolution of market design. With an amendment of this notion at the level of the REMIT Regulation, also key complex entities (e.g. consortia of organised marketplaces) would fall under the scope of REMIT, allowing ACER to monitor crucial markets such as coupled markets and new balancing ones. Additionally, the definition of wholesale energy market in Article 2 of REMIT does not clearly include all wholesale energy markets coupled within European coupling projects such as those defined in the CACM Regulation. Moreover, in order to overcome potential gaps in data reporting related to these markets, ACER would propose that in order to be considered a 'wholesale energy product' it is sufficient for a product to have the "potential delivery" in the Union.

In addition, contracts for balancing services, which are currently reportable at the request of the Agency, should be reported to the Agency on a continuous basis. This would allow the Agency to monitor the markets in light of the developments under the Clean Energy Package. Wholesale energy products traded as part of capacity mechanisms should also be reportable to the Agency.

# Annex I: Additional Important Aspects of Electricity Market Design

In addition to our consultation response, ACER and CEER delve deeper into three elements that are subject to consultation: 1.) contracts for difference; 2.) intraday cross-zonal gate closure time; and 3.) obligations on suppliers to offer fixed-price contracts to household consumers. Finally, ACER and CEER highlight several important aspects of the electricity market design framework that were not addressed by the Commission in its consultation. Yet, in our opinion, these also have a significant impact on electricity market functioning.

## 1. Risks and opportunities of a two-way Contract for Difference (CfD)

EU regulators understand the typical two-way CfD entails (i) the state as a single buyer, (ii) settlement with single strike price (typically against the DA price) and based on the volume produced and (iii) direct settlement with all consumers through taxes and levies (bonus or malus). These kinds of CfDs come with risks and opportunities:

Risks:

- (a) They may have a negative impact on short-term markets such as providing inefficient dispatch incentives (e.g. if the generator gets paid based on physical volume produced then it has an incentive to producing even when prices are below its marginal costs). This could also impact investment efficiency (maximising generation output rather than market value).
- (b) They may significantly reduce the liquidity of forward markets as well as reduce the scope for competition in retail markets.
- (c) They may reduce the investment uncertainty more than necessary. It may be rational or enough to reduce only extreme uncertainty faced by investors, whereas the normal uncertainty (faced by investors in all economic sectors) should remain with investors.
- (d) Similar to RES subsidies, they may lock-in the average price for consumers for very long periods (e.g. 20 years) for the volume of contracted CfDs and without taking into account consumer's preferences. Instead, it might be enough to protect consumers against sustained periods of high prices.
- (e) They could lead to (on average) higher prices for consumers as the competition at CfD auctions may not achieve the level of competition experienced within integrated short-term markets (e.g. due to lack of internal competitors, no cross-border competition, high risk premia).
- (f) Central procurement of CfDs by the state may end up in an inefficient outcome of over dimensioning and overinvestment of electricity system historically observed in regulated electricity systems and result in higher costs for consumers; and
- (g) As the design of state contracts may depend on specific technology, such centrally procured contracts risk making arbitrary (and possibly suboptimal) decisions on the extent to which (certain) technologies are subsidised. This may hamper incentives for innovation of other new and more efficient technologies.

Opportunities:

- (a) They can provide an effective protection of consumers against high prices (but at the expense of removing the benefits of low prices), if positive and negative differences are channelled back to consumers;
- (b) They could be an effective and possible way to support investments in new capacity as they provide price stability and investment certainty. Such certainly would minimise the costs of capital for investors;
- (c) They could be an effective and possible way to replace inframarginal revenue cap; and
- (d) They may provide an effective means to achieve decarbonisation targets with more certainty and predictability.



However, EU regulators look optimistically towards a smarter design of CfDs, which could entail the following improvements:

1. Settlement based on a predefined volume or reference volume (e.g. reference wind turbine);
2. Cap and floor instead of a single strike price;
3. Reselling of CfDs as financial contracts (e.g. futures) in forward markets closer to delivery (up to 3 years) and no direct settlement with consumers.

EU regulators call for careful design and harmonisation of design principles of such contracts (e.g. through European Commission guidelines).

## **2. Requiring suppliers to offer fixed price fixed term contracts**

Consumers are affected by higher and more volatile prices. In many European markets, some consumers value predictable prices and demand fixed-price and fixed-term contracts. In some markets, these contracts are currently not available at all whereas in other markets there are a wide variety of fixed-price fixed-term contracts to choose from.

Importantly, a fixed price is not necessarily a low price. Fixed-price, fixed-term contracts protect consumers from volatile prices, not from high prices. Price data and case studies provided by individual National Regulatory Authorities (NRAs) show that, over time, variable and dynamic contracts have given consumers lower annual costs than fixed price contracts. In the current market situation, when future prices are difficult to predict, fewer suppliers offer fixed-price fixed-term contracts. Currently, suppliers that still offer these products do so at very high prices. A mandatory fixed price contract has been tested in Spain, where the NRA concluded that it did not improve customers' situation.

If mandatory, customers in Member States currently without these contracts would be able to sign contracts with a predictable and stable price, but the prices offered could be expensive. Requiring suppliers to offer fixed price contracts may raise costs if there is no demand for such contracts. Also, it requires time and competence for suppliers to offer them.

If provisions requiring suppliers to offer fixed price fixed term contracts are introduced, it should be voluntary for each Member State to implement them nationally. NRAs could support the mirroring of requirements for dynamic contracts (e.g. suppliers with more than 200,000 customers) being required to offer fixed price fixed term contracts. If mandatory for all suppliers, it could result in a market entry barrier.

## **3. The adequacy of minimum cross-zonal electricity capacity requirements**

The Clean Energy Package imposed new requirements for cross-zonal electricity capacities being offered for cross-zonal trade (Article 16(8) of the Regulation (EU) 2019/943). This obligation applied from 1 January 2020 and energy regulators continuously monitor the fulfilment of the 70% targets. Yet the monitoring results show that for some bidding zones little progress has been achieved so far. ACER and CEER invite the European Commission to (i) assess which legal provisions are most suitable to address the lacking progress, (ii) specify clearer provisions for granting (recurring) derogations and (iii) provide more explicit obligations for and guidance to NRAs and ACER for monitoring compliance with the minimum cross-zonal capacity requirement provisions, applying the requirement to other than day-ahead timeframe.

## **4. The importance of the integrated intraday and balancing market**

The need to decarbonise the EU electricity market implies a significant penetration of variable renewable energy sources (VRES) combined with nuclear and flexible generation technologies such as hydro, storage, demand response, and biogas/hydrogen. Due to the inherent volatility of VRES production and the associated uncertainties, intraday and balancing markets will need to adapt to

rapidly changing weather conditions. Also, those close to real time markets must remain highly integrated across borders in the sense that interconnection capacities must be frequently reassessed and fully utilised to maximise the potential of VRES production to reach consumers throughout Europe.

Yet, recent experience shows difficulties by Member States to achieve the 70% cross-zonal capacity targets in the intraday and balancing timeframe. To avoid a failure of the intraday and balancing market integration, energy regulators invite the European Commission to examine this problem and to propose adequate solutions in EU legislation. A number of possible options could make the 70% targets feasible such as: (i) a reconfiguration of the bidding zones, (ii) network investments (action plans), (iii) the application of redispatching after capacity allocation in intraday and balancing timeframe and (iv) a definition of optimal capacity allocation structure across different market timeframes. However these solutions need to be balanced with regard to market timeframes, VRES integration (and CO<sub>2</sub> reductions), avoiding increasing redispatching needs and ensuring market stability with regard to the bidding zone configuration.

## **5. Continuous growth of implementation delays in key integration projects**

Electricity market integration is a continuous process of (i) monitoring market functioning, (ii) identifying inefficiencies, (iii) designing improvements and (iv) implementing market design improvements. Europe's energy regulators observe that this process cycle is too slow to be able to adapt to the needs of the fast-moving landscape of decarbonisation and change of associated technologies. Furthermore, any change of market design requires significant time (judged by the mere technical challenges). One example is the flow-based capacity calculation project in the Core region which experienced several delays and was finally implemented in 2022 (seven years after the adoption of the CACM Regulation), whereas flow-based capacity calculation in the Nordic region is still not implemented. Such delays can be measured against socio-economic welfare losses because they are implemented much later than what they should be. Regulators call for an analysis of whether the overall governance and organisation of the EU internal electricity market is still fit for the purpose to deliver integration projects and bring their benefits to EU consumers in reasonable time. In the context of the current energy crisis, many stakeholders also asked for significant market design reforms. Europe's energy regulators emphasise that the EU framework does not allow for fast adaptation of the market design, which would be required to address the emerging problems.

## **6. The adjustment mechanism for decrease of maximum clearing and bidding prices**

The day-ahead and intraday markets in Europe have a mechanism for automatically increasing their maximum and minimum clearing prices in case extreme market prices occur. This mechanism is designed for gradual increases of the price limits in order to allow for an optimal short-term dispatch of generation, an efficient use of interconnections and to encourage demand response.

According to Article 10(2) of Regulation (EU) 2019/943, the effect of those price increases is permanent until further adjustments under that mechanism are required. ACER and CEER realise that the adjustments of the price limits can be triggered by purely circumstantial events, yet such increases would last indefinitely. Regulators therefore call for an assessment on the need to allow for a decrease in the maximum clearing prices. On the one hand, the possibility for maximum prices to decrease may provide an additional layer of protection to consumers that are exposed to day-ahead prices. On the other hand, many times the automatic increase applies only after a maximum price has been reached. Hence, a decrease of the maximum prices may further restrict free price formation and dampen the price signals for demand response and flexible generation and endanger the adequacy policy of those Member States that rely on price signals to deliver necessary investments in flexibility.

## **7. Legal framework for offshore wind**

A significant amount of investment in offshore wind is expected in the near future. Investors (in offshore wind) need a stable and predictable legal framework to enable them to estimate their future revenues.

Yet, the legal and regulatory framework for offshore wind is still very much undefined. Energy regulators published in 2022 [a reflection on the EU strategy to harness the potential of offshore renewable energy for a climate neutral future](#). In this reflection, regulators outlined several proposals for strengthening the legal framework for investments in offshore wind. In particular, they emphasised that congestion in hybrid offshore networks could best be managed with offshore bidding zones and the opportunities to plan and invest in hybrid offshore networks to further integrate EU electricity market. Yet, this policy comes with specific new challenges that need to be addressed at EU level with an appropriate legal and regulatory framework. Among them, it seems that the viability of offshore bidding zones to ensure sufficient intraday and balancing cross-zonal capacities is an important pre-condition. The EU electricity market design reform provides an opportunity to develop such a framework.