European Network of
Transmission System Operators
for Electricity

ENTSO-E RESPONSE TO THE EUROPEAN COMMISSION PUBLIC CONSULTATION: REVISION OF THE EU'S ELECTRICITY MARKET DESIGN

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SECTION: MAKING ELECTRICITY BILLS INDEPENDENT OF SHORT-TERM MARKETS

Subtopic: Power Purchase Agreements (PPAs)

Question 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?

Yes

Question 2 Please describe the barriers that currently prevent the conclusion of PPAs:

The PPA market today is dominated by large players. This is largely due to long contract durations for new assets and high collaterals required to enter into a PPA agreements. Countries such as Spain, France and Norway introduced credit risk schemes to this end. In addition, PPA agreements are non-standard and require a lot of consideration to enter into. Repackaging by the supplier is possible, but smaller-scale consumers are in many cases excluded from the PPA market. Opening up the demand side for PPAs could accelerate their growth. It is furthermore hard for some consumer types to assess their electricity needs in the long run.

The lack of interconnection infrastructure between different EU countries can limit the volumes and make it more difficult for companies to enter into PPAs. Even for purely financial contracts, which are in essence equivalent to physical PPAs, the lack of transport capacity can lead to an increased risk of price spread between zones. This includes upgrading existing interconnection infrastructure and building new interconnection lines.

In the current crisis, there is little incentive to sign PPAs, as consumers do not wat to lock themselves in high prices and generators are able to profit from revenues from the spot market. Additionally, there is a high uncertainty regarding evolution of future prices, bidding zone reconfigurations, and potential political interventions. Overall, these factors present a risk for fixed prices and arrangements under the PPAs. It should be kept in mind that PPAs can mitigate short-term price volatility, but also lock-in a price for the long-term, creating a risk of missing out on a better price later on. Solid revenue security on the long-term might reawaken an interest in PPAs. Exposing PPAs to the risk of windfall tax, for example, hampers such agreements.

Question 3 Do you consider that the following measures would be effective in strengthening the roll-out of PPAs? (6 choices max)

Answer: **b & c**

Available choices:

~~a) Pooling demand in order to give access to smaller final customers~~
~~b)~~ Providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks)
~~c)~~ Promoting State-supported schemes that can be combined with PPAs
~~d) Promoting standardization of contracts~~
~~e) Requiring suppliers to procure a predefined share of their consumers' energy through PPAs f) Facilitating cross-border PPAs~~

Question 3.1 Do you have additional comments?

It should be recognized that PPAs are perceived as purely commercial contracts however, considering interventions such as the ones described above risks creating a type of "hidden" subsidy for such agreements. This would lead to society bearing a cost/risk to support/de-risk a contract which favours selected parties. It could also negatively affect competition with other, more cost-efficient products.

Regarding promotion of standardisation of the PPA contracts (d), while it would reduce administrative burden on PPAs it could also potentially lead to locking-in of the negative effect for the off-taker and duplication of possible design errors in the contract design. PPAs are bilateral agreements and parties should have freedom over contents of these agreements.

Cross-border PPAs are already possible with virtual PPAs. The main risk is price spread, which can only be mitigated through a state-backed schemes, in which case, you might opt for proposal under point (c). The "carve-out" mechanism in question 28 could be considered to meet point (c). In addition, the suggestion to offer CfD volumes to consumers in question 22 could offer PPA-like hedging vehicles to all consumers, incl. those with no access to that market today. Standardized contracts (d) would also be of aid to facilitate this though the higher-mentioned risks of standardization should be considered.

As mentioned in Question 2 on PPAs, a proper infrastructure would strengthen the roll out of PPAs. In this regard, the achievement of the electricity interconnection target of at least 15 % for 2030, set in the Governance Regulation, provided that system benefits outweigh costs, is key to enable PPA, to fulfil the goals of the Energy Union and the Green Deal and facilitates the cost-effective integration of the growing share of RES.

Question 4 In addition to the measures proposed in the question above, 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?

Yes

Question 4.1 If yes, please explain which rules should be revised and the reasons? If no, please explain

The current emergency measures and other revenue cap mechanisms**,** aiming at protecting consumers in period of crisis against sustained high market prices, pose a threat of lowering appetite for new investments in case they don't guarantee correct accounting for PPAs, If they are to be kept, they should at least properly account for PPAs and other long-term commitments to ensure they are not hampered.
Moreover, it must be ensured that the design of CfDs and/or PPAs supports or does not hinder the provision of flexibility by market parties, including via balancing and ancillary services which are essential for system security. In this context, procurement timeframes of ancillary services may also need to be revised in the future to ensure liquidity and cost-effectiveness.

Question 5 Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity?

No

Question 5.1 If yes, under which conditions? What would be the benefits and challenges? If no, please explain

The preferred approach would be to foster and expand PPA markets in accordance with the suggestions made above, in order to make an appropriate use of PPAs. This will maximize the true value of this hedging/investment vehicle. By comparison, ill-considered incentive schemes risk over-subsidizing PPAs, which inflates overall costs. Mandatory shares of PPAs may distort market demands by locking in demand for fixed contracts and hampering the development of flexibility (particularly DSR). The alternative, to foster liquid forward markets and ensure accessibility of hedging opportunities to market parties (and in the end: the consumers), seems a more efficient way to achieve the intended goals.

Question 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?

No answer

Question 7 Do you consider that increasing the uptake of PPAs would entail risks as regards

	Yes	No
(a) Liquidity in short-term markets		x
(b) Level playing field between undertakings of different sizes		x
(c) Level playing field between undertakings located in different Member States	x	
(d) Increased electricity generation based on fossil fuels		x
(e) Increased costs for consumers		x

Text reply:

While ENTSO-E indicates the risk for liquidity in short-term markets as "no", it should be noted that this is under the assumption that the increase in PPA uptake occurs in an optimal way, i.e., by improving on the markets and not by imposing PPA contracts. Otherwise, the risk could become quite severe, particularly in taking flexible resources out of the short-term markets and hampering the development of flexibility in the long run, thus reducing liquidity in ancillary/balancing markets.

In addition, some degree of harmonization between Member States is likely desirable to retain a competitive European market. In particular, if there were forms of support schemes making PPAs particularly attractive, this may influence the cost of electricity in that area and in turn incentivise the development of energyintensive consumers and demand side flexibility.

Finally, it should be noted that both PPAs and CfDs have a merit in managing the cost for the end consumer (point e). PPAs are a versatile, commercial instruments that allow parties to define optimal arrangements for them. For CfDs, competition in dedicated, open tenders on the generation side could lead to pricing close to the levelized cost of electricity (LCOE) and with reduced capital costs. However, the risks and preferred design features for CfDs presented in the dedicated section of this questionnaire should be thoroughly considered.

Subtopic: Forward Markets

Question 8 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?

Yes

Question 9 Do you consider that the liquidity in forward markets is currently sufficient to meet this objective?

No

Question 9.1 Do you have additional comments?

In principle, forward markets can provide important long-term signals to incentivise investments in new capacity. However, they are not sufficient to support investments in low-carbon generation nor to ensure resource adequacy in a rapidly evolving market and policy environment, also considering the absence of liquidity on longer durations products (> 10y) which is likely to persist. To manage a rapid energy transition in a secure manner we thus see Capacity Mechanisms necessary in most markets (see answer to Q52) to ensure sufficient dispatchable resources in the system. These should complement CfDs and PPAs for investment signals in low-carbon generation resources.

Current forward markets in Europe have very different levels of liquidity. Although there are a few highly liquid ones, most of the bidding zones (BZ) are illiquid. However, a distinction between hedging within a BZ and across borders must be made, as TSOs are only involved in providing hedging possibilities across borders via long-term transmission rights. With sufficiently liquid forward markets in all BZs, market participants could obtain effective and efficient hedges against the volatility of the spot prices in any BZ simply by entering a transaction for the corresponding forward market. However, due to several factors such as their limited sizes, most national markets are not sufficiently liquid. For such illiquid markets, either access to other liquid markets or measures to increase local liquidity should be considered. Access to other liquid markets should not hamper the development of local liquidity by draining it into neighbouring markets. As per measures to increase local liquidity, these must aim primarily at a cost-efficiency and be in the ultimate interest of end consumers. The reasons for illiquidity shall be carefully analysed and possible solutions out of the TSOs' ambit should also be considered.

Question 10 In your view, what prevents participants from entering into forward contracts?

First of all, we would like to highlight that this issue is out of scope of the TSOs' influence and we only reply to this question based on our understanding of the market as described in our Policy Paper on "EU's electricity forward markets".

In ENTSO-E's view, in some countries many participants (generators) seem to not feel a need to enter into organised forward markets because they prefer supplying directly to the end consumers (vertically integrated companies, PPAs, reliable partners, etc.). Therefore, they may offer only part (if any) of their production at the organised market. However, one basic prerequisite to enable functioning organised forward markets and foster liquidity is an environment free from hidden and/or indirect barriers that hamper the development of such markets.

Potential barriers from the point of view of ENTSO-E include: the collateral systems of commodity and, financial regulation provisions that may end up incentivising Over-The-Counter trading as well as regulatory interventions like regulated/fixed prices, reserve capacities or subsidies. In our view, improving simplicity and transparency for market participants seems to be another key prerequisite for the markets to develop and increase the level of liquidity. Having a mismatch between supply and demand in a bidding zone can be seen as another relevant factor. Policy makers should carefully analyse all potential barriers of entry, especially in illiquid bidding zones. However, these issues are outside of the TSOs' influence and cannot be solved by LTTRs and their design.

Question 11 In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?

No answer

Question 11.1 Do you have additional comments?

No answer

Question 12 Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets?

No answer

Question 12.1 If yes, do you consider that such virtual hub(s) should be developed at national, regional or EU level?

No answer

Question 12.2 Do you have additional comments?

No answer

Question 13 Do you have experience with the existing virtual hubs in the Nordic countries? –

No

Question 13.1 In case you have experience with the existing virtual hubs in the Nordic countries, how do you rate this experience?

No answer

Question 13.2 Do you have additional comments related to the existing virtual hubs in the Nordic countries?

ENTSO-E as an association does not have experience with virtual hubs, however, the Nordic TSOs have had the following experience:
The Nordic market has been known for providing a generally well-functioning hedging setup managed by fully commercial markets linked to the "system price", the theoretical price without transmission constraints in the Nordic area. Nordic TSOs are generally not offering long-term transmission rights (LTTRs) or other financial products to market participants. However, the financial market in the Nordic has, since 2008, been suffering from decreasing liquidity and trading interest like many forward electricity markets in EU have. To a large degree, the decreasing in the Nordic market stems from increasing costs for collateral and reporting caused by the introduction of MIFID II and EMIR (bank guarantees defined as invalid in financial regulation in 2018) and the following transition to bilateral trading/hedging by a significant number of market participants, in particular RE-generators with a electricity generation profile deviating from forward products, baseload and peakload.
This development teaches Nordic TSOs the important lesson that it is not in itself sufficient to introduce new or even improved instruments by itself, i.e., the demand needs to be sufficient for the new products. They also need to be offered in a trading environment that makes it cost efficient for market participants to use them. One additional issue besides the changes in collateral requirements to be mentioned is the declining correlation between bidding zone prices and the system price during the recent energy crises. This however will likely improve as the situation returns to stability.

Question 14 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?

ENTSO-E would like to point out that the forward market is a commodity market first. In this context TSOs come only into play by providing long-term transmission rights (LTTRs) in auctions, which is a comparably small market.

ENTSO-E considers that the changes in market fundamentals require a reconsideration of the current design of forward markets to make them fit-for-purpose and to ensure the better protection of market participants, retail suppliers and consumers. In case, the perceived current challenges of the forward markets such as apparent low liquidity and undervaluation of LTTRs requires improved hedging instruments or market models, ENTSO-E is happy to support any such initiative.

In the ENTSO-E Policy Paper on "EU's electricity forward markets"[1], the TSOs are exploring the current state of these markets, particularly considering four main aspects: 1. Meeting the demand of increased hedging due to greater RES penetration; 2. Increasing the liquidity in illiquid forward markets; 3. The interests of end consumers; and 4. The risks of capacity calculation in the long-term timeframe. In this context, ENTSO-E provides an initial analysis on possible policy options with three approaches. The evaluation of the three main approaches shows that all of them will solve some of the observed challenges. However, at the same time, all approaches have drawbacks and come with a shift of risks between TSOs, market participants and endconsumers. For instance, offering LTTRs up to approximately 3 years in advance is seen very critical from a TSO perspective, especially when intended as cross-zonal hedging, due to huge uncertainty that comes along with the extension of the time horizon and the higher financial burden on end consumers due to the risk shift from market participants to TSOs.

[1] *https://www.entsoe.eu/news/2022/12/23/eu-s-electricity-forward-markets-policy-paper/*

Subtopic: Contracts for Difference (CfDs)

Question 15 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)?

Yes

Question 15.1 Do you have additional comments?

First and foremost, it is imperative for the continued well-functioning of the electricity market as well as the effectiveness of such mechanisms that 2-sided CfDs do not distort the market. To that end, CfDs should be decoupled from the dispatch decision (i.e., not based on injection) and a non-distortive two-sided CfD design is necessary (such as capability-based CfDs, cf. Q20 & Q 21). To facilitate development of new generation assets in line with system requirements and transmission constraints, locational signals or constraints could be introduced in auctions for CfDs, but require further consideration. In any case, CfDs should be designed so they do not hamper participation in Ancillary Services market in order to maintain liquidity in those markets.

A two-way CfD allows to provide long-term price stability for both inframarginal generators and governments. Difference payments can be redistributed through policy choices. However, if such policies are decided ad hoc, this would lead to an unnecessary uncertainty in government net revenues that must be corrected by (often distortionary) short-term levies and subsidies to support consumers. Moreover, liquidity in the forward market and price signals incentivizing demand side flexibility could be hampered in such a case. A transparent, market-based, cost-effective and structural mechanism should resolve these concerns and provide certainty and efficient allocation to end consumers in the long run. Suggestions to this effect can be found in question (CfD Q7, as per consultation document numbering).

Conversely, the compensation for generators offers them a hedge for the price risk. Hence, generators have security for their investments and consumers have hedging opportunities available to shield them from high prices. CfDs would therefore constitute an efficient tool to achieve different sets of policy objectives. CfDs offer generators a hedge for the price risk leading to lower capital costs for these investment projects.

Question 16 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?

Yes

Question 16.1 Do you have additional comments?

ENTSO-E would like to stress, as underlined in the previous question, how imperative it is for the wellfunctioning of the market that if such mechanisms are to be implemented they should not distort short-term prices: CfD designs that decouple the CfD from the dispatch decision of the asset are therefore key to ensure this principle (see also question 21).

It should be noted that CfD-backed RES can develop alongside commercial PPA-backed RES. It requires a smart allocation and clear separation of capacity between both (e.g. through a "carve-out" mechanism where a share of the capacity is under PPA and a share under CfD). However, hidden subsidies should be avoided to ensure risks are allocated to the appropriate parties and in order to retain market incentives in the interest of the system.

Further, CfDs with inframarginal generators alone don't mitigate price spikes for consumers. There should be a well-considered allocation mechanism, such as the suggestions in question 22.

Other options for supporting inframarginal electricity generation could also stimulate investment such as capacity-based support schemes for a maximum number of full load hours guaranteeing a minimum revenue, but also here they should be non-distortive with regards to dispatch and market prices. In particular, the support scheme should not be tied to injection.

Question 17 What power generation technologies should be subject to two-way contracts for difference or similar arrangements?

Two-way CfDs could be awarded to low-carbon weather-dependent, or otherwise, inflexible generation technologies. On the other hand, flexible resources should remain exposed to price variations.

Question 18 Why should those technologies be subject to two-way contracts for differences or similar arrangements?

Ambitious policy objectives have been set to reach decarbonisation goals. They can be considered as market interventions from the perspective of an energy only market. It is unsure whether the market alone (e.g. through commercial PPAs) can be sufficient to reach those policy objectives. Hence, it makes sense to develop instruments supporting these targets. They can be seen as specific instrument complementing the energy market. A well-designed, non-distortive CfD has key benefits in this regard (cf. question 15.1). Such mechanisms, when correctly designed, are by far preferable to market interventions (cf. question 34) which can undermine the correct functioning of short-term markets.

Question 19 What technologies should be excluded and why?

Carbon intensive technologies should be excluded since they do not need to be inframarginal, flexible, not weather-dependent and hence not well-suited for a CfD. Such support schemes should be used to accelerate the energy transition and allow Member states to reach the Fit for 55 and net zero targets. In light of these uncertainties, flexible generators which are necessary for ensuring system security and security of supply should be incentivised by other means, e.g. Capacity Remuneration Mechanisms.

Question 20 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?

In injection-based CfDs, the operators receive/provide a payment corresponding to the difference between the strike price and DA prices multiplied by the energy volumes injected by the renewable installation. Just as with strictly one-sided CfDs (i.e., support when prices are low), operators are incentivized to maximize the production volume, regardless of the actual market situation ("produce and forget"), with the following adverse effects:

- RES installations feed-in even if the DA prices are negative;
- Market-based intraday curtailment or provision of negative balancing services is limited to situations where the price drops below (- strike price);
- Prevention (e.g. by full reservation of the capacity) or demotivation of participation in complementary short-term markets (balancing, ancillary services);

In addition, in a 2-sided injection-based CfD policy makers should be aware that there are many more cases where distortions occur. In certain situations, it can lead to artificially increased costs of RES energy and RES sources intentionally reducing production.

In all cases, such support schemes compromise the efficient dispatch of resources through short-term markets. Furthermore, the lack of exposure to market signals also leads to suboptimal investment decisions, hamper liquidity in forward and PPA markets and, depending on the redistribution mechanism, limit incentives for Demand Response.

These problems could be avoided with well-designed CfDs. To that extent, a variety of non-distortive twosided CfD designs, decoupling the CfD from the dispatch decision of the asset, are to be considered (such as capability-based CfDs, cf. Question 21). ENTSO-E and its members have carefully assessed various designs and are ready to share more insights for good designs. Moreover, redistribution issues (cf. Q22) should be considered to retain appropriate DSR incentives. Coexistence of PPAs with CfDs could retain liquidity in the PPA market.

Question 21 What design principles could help mitigate the risks identified in your reply to the question above, in particular, in terms of procurement principles and pay out design? Should these principles depend on the technology procured?

To ensure incentives for optimal dispatch behaviour, volumes paid out under CfDs should be decoupled from the actual injection. Examples are:

- Capability-based CfDs: Power plant owners compete in an auction for a fixed strike price. The payment is based on the volumes that "could" be produced by the installation, based on technical characteristics and local weather conditions. Such a signal is already used by some TSOs in balancing products.
- Financial CfDs: The government provides a fixed hourly lump-sum. The generator pays the government the hourly spot market revenues – but not the actual revenues, but benchmark revenues based on a reference profile.

The design of these measures can vary. The preferred design is a matter of further discussion, but it seems highly feasible to come up with an efficient solution. Each option brings the advantage that they eliminate distortive dispatch incentives in the short-term markets of injection-based CfDs.

With capability-based CfDs, the revenue of the producer is not affected by welfare-enhancing measures such as (introduction of new bidding zones, the commissioning of new interconnectors…). In addition, the granularity of the volume definition is specific to the plant, which should lower risk for the generator owner and suppress costs of the mechanism.

Financial CfDs directly incentivize to optimize market revenues. This means that operators will plan maintenance during expected low-price periods. In addition, there is a stimulus for the diversification within the technology classes to reduce cannibalization effects (e.g., PV systems with an east/west orientation or low wind turbines). An advantage from the perspective of the operators is that they also have a hedge for the generation volume. In a low-wind month, spot revenues are low, but so is the payback to the state.

The risks regarding forward markets and DSR development should be tackled by the redistribution design (cf. Q22) and coexistence models with PPAs.

Question 22 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?

As stated previously, transparent, market-based, cost-effective and structural mechanism is strongly preferable to also provide certainty and efficient allocation to end consumers in the long run, as opposed to ad-hoc policy measures.

An economically sound way of doing so would be to trade the volumes resulting from CfDs as hedging options for electricity consumers which would provide more stability both to the government and to the consumers. This concept works as a "back-to-back tender", where generation is tendered on one side, and this volume is passed to consumers on the other. Governments can hold competitive auctions for financial products where they bid strike prices for the volume of generator CfDs. The central counterparty in such a mechanism can opt to decouple the contract lengths from those on supply side, creating the opportunity for shorter and periodically re-auctioned contracts for consumers. As an alternative, CfD volumes could be resold as new standardized products in future markets. Careful design of the allocation mechanism is required to avoid any risks/inefficiencies.

Further regulation to limit the cost for the end consumer through such a mechanism is possible but is a policy choice and potential distortive effects should be considered. Particular risks are the discriminatory treatment of some consumer types and hampering the efficient development of demand side response, although this could be addressed, cf. questions 46 and 57. Other examples of more policy-driven allocation are integration through a regulated retail price when there is one, obligation for suppliers to transfer the costs or pay-out to their consumers, etc.

Question 23 What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type?

Yes, it should differ depending on the technology type. It could potentially be awarded based on a regulatory audit. A priori, it makes sense to relate it to the economic lifetime of the investment, as is often done in support schemes today (typically starting at 15 years for new investments). Another option would be to a apply CfDs for a maximum number of full load hours instead.

Question 24 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?

No answer

Question 25 Without prejudice to Article 6 of Directive (EU)2018/2001[1], should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity?

Article 6 (1): Without prejudice to adaptations necessary to comply with Articles 107 and 108 TFEU, Member States shall ensure that the level of, and the conditions attached to, the support granted to renewable energy projects are not revised in a way that negatively affects the rights conferred thereunder and undermines the economic viability of projects that already benefit from support.

Article 6(2): Member States may adjust the level of support in accordance with objective criteria, provided that such criteria are established in the original design of the support scheme.

No

Question 25.1 If yes, 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)?

No answer

Question 25.2 Under what terms and conditions could regulated two-way CfDs on existing generation capacity be imposed?

No answer

Question 25.3 If no, Do you have additional comments??

Imposing CfDs to existing assets leads to difficult negotiations with the owners of such assets. In the current context it risks creating a power dynamic that a priori favours the generator owners; in that sense, it risks inflating the bill for the end consumer in the long run.

We should not forget that the current situation is unprecedented, and that the future most probably will see long periods of low prices caused by renewable development. Fixed, regulated prices with existing generation will then most probably result in consumers paying much more than the market price. Conversely, such measures also undermine overall market optimism and could further discourage needed investments.
However, ENTSO-E considers that, instead of such a compulsory approach, it still should be a possibility for Member States to sign such contracts with voluntary generators. The framework of such contracts should focus on:

- direct or indirect impacts on market and system integration aspects avoiding distorting market signals;
- Incentives for RES units to provide system services, including balancing, non-frequency ancillary services and correctly forecast their production, eliminating risk of excessive support;
- proper calculation of reference prices;
- high competition between generation sources resulting in appropriate price signals;
- proper definition of contract timeframes to reflect decreasing technology prices;
- limiting contracts to technologies with long-term revenue risks;
- balancing the need for sufficient investment stability while avoiding overcompensation.

Different types of CfDs/PPAs will play an increasing role in the market by facilitating some installations to be built and operated; however, they cannot be treated as a silver bullet for all problems the European energy system is facing today. These go much deeper than that: the currently high electricity prices are derivative of underlying market fundamentals, i.e. where the revenues and costs originate.

Question 26 How would you rate the following potential risks as regards the imposition of regulated CfDs on existing generation capacity?

No answer

	Negligible risks	Low risks	Medium risks	High risks	Very high risks
Legitimate expectations/legal risks					
Ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts					
Locking in existing capacity at excessively high price levels determined by the current crisis situation					
Impact on the efficient short-term dispatch					

Question 27 Would it be enough for existing generation to be subject only to a simple revenue ceiling instead of a revenue guarantee?

No

Question 27.1 Do you have additional comments?

A revenue cap limits the appeal to invest in the energy market, whereas we rely on substantial investments to achieve the energy transition. A simple revenue cap compromises timely achievement of the energy transition. Furthermore, if CfD support schemes are well-designed and competitive, i.e. generators would bid competitively for a limited volume of such contracts, they should lead to a least-cost revenue guarantee in the long run anyway through the resulting level of the strike price.

The experience of the implementation of the revenue cap from the emergency measure regulation hints that a revenue cap is complex to implement, legally uncertain, and leads to much less pay back than expected, mostly due to the consideration of hedged volume. Additionally, a one-way mechanism like this bears additional legal risks, stemming from the fact that the economic risk is not shared. This would most probably affect the legal assessment with regard to legitimate expectations and could raise the standard on the required legal basis.

On a side note, ENTSO-E would like to stress that the introduction, irrespective of the technology perimeter they encompass, of CfD mechanisms is fully compatible with the introduction of capacity mechanisms (or the presence of existing ones) and the first should not lead to questioning the relevance of the latter. Both types of mechanisms aim at addressing different purposes and, provided a given capacity does not get compensated twice, their coexistence should be allowed by the market design framework, as it is already the cases in some Member States for RES under CfD-like support schemes.

Question 28 What are the relative merits of PPAs, CfDs and forward hedging to mitigate exposure to shortterm 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?

To achieve a carbon-neutral power system, we need to strengthen long term signals for investment in both low-carbon generation assets and flexibility resources to support both the wholesale electricity and ancillary/balancing services market. For the former, a combination of 2-ways CfDs and PPAs has the potential to support investments in new capacity while also mitigating exposure of end-user bills to price shocks. However, it is essential to design CfDs and PPAs so to ensure that the resources covered by these instruments are efficiently dispatched and to avoid any distortion or liquidity decrease in spot and balancing markets which are key for efficient use of infrastructure and system stability.

All products have merit and appeal to different stakeholders. Forward hedging entails a very generic electricity commodity, tailoring to large consumers, energy suppliers, owners of large dispatchable assets and/or large pools of assets. PPAs, on the other hand, are particularly appealing to support investments in specific assets, such as RES. In addition, they offer clean power at a stable price to consumers. However, both consumer and RES asset owner in this case are typically a large entity. CfDs and the associated method to return their benefits to all end consumers (cf. Q21) can appeal to smaller developers and consumers as well. Because of this, the coexistence of these products can provide an inclusive and sustainable hedging climate.

The coexistence of notably CfDs and commercial PPAs could already be ensured as of the tendering phase for the CfDs, for example by a "carve-out" mechanism. Therein, a generator participating in the tender could exempt a share of its capacity from the CfD and develop it under a commercial PPA instead. If the tender is competitive, this could lead to reduced costs for the CfD through a potential margin on the PPA contract. It should further reduce the dependence on subsidy.

Subtopic: Accelerating the deployment of renewables

[1] See the recommendations of the Study "Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market" https://energy.ec.europa.eu/system/files/2022-09/Congestion%20offshore%20BZ.ENGIE%20Impact.FinalReport_topublish.pdf

Question 29 Do you consider that a transmission access guarantee could be appropriate to support offshore renewables?

No

Question 29.1 If yes, Do you have additional comments? If no, Please explain and outline possible alternatives.

It may be a normal market outcome that offshore renewable assets are not selected in the market. To avoid discrimination, this should not lead to compensation other than a possible support scheme (see Regulation (EU) 2019/943, Art. 12). If the offshore renewable assets are prevented to inject due to redispatching necessary to alleviate a grid congestion, a compensation is typically already foreseen within the national redispatching regime.

In a scenario with offshore bidding zones in place, there is indeed a risk posed to developers *due to the results of the capacity calculation process* over one or more of the interconnector(s) to which they are connected (this does not apply to radially connected RES). However, ENTSO-E believes that current rules on congestion income use maximise benefits for tariff payers. Furthermore, congestion income sharing with producers is a non-proportionate hidden subsidy for one specific technology funded by the tariff payer, which may be considered as discriminatory. It risks aggravating windfall profits not in the least because TAG can lead to overcompensation. There is no such guarantee whether the congestion income allocated to the windfarm is sufficient or excessive: when the spread is low, revenues are insufficient and when revenues are high, no profits are returned to the tariff payer (see also ENTSO-E Position on Offshore Development - Assessing Selected Financial Support Options for Renewable Generation[2]).

Finally, these risks, distortions and hidden costs are far from justified as the "TAG" would address a small part of the problem. The much larger issue is that of ensuring a clear case for investing in OWFs connected to a hybrid, which is closely linked to the low and volatile revenues they would get in an OBZ even when transmission capacity is available. In case public support is needed, there are more cost-efficient, transparent and proportionate mechanisms such as 2-sided capability-based CfDs.

Question 30 Do you see any other short-term measures to accelerate the deployment of renewables?

	Yes	No
At national regulatory or administrative level	X	
In the implementation of the current EU legislation, including by developing network codes and guidelines	X	
Via changes to the current electricity market design	X	
Other	x	

Question 30.1 If yes, please specify.

From a TSO perspective, it's essential to coordinate the acceleration of RES development with the necessary development of transmission grids and system flexibility to ensure resource adequacy, system stability and resilience at all times.

The existing barriers for the development of RES should be removed, ensuring a stable regulatory and investment framework, while preserving environmental protection. More precisely, ENTSO-E welcomes an improved regulatory framework and stakeholder engagement to speed up permitting processes and acceptability. Concrete targeted measures should be in place to guarantee adherence to the planned timeline. The regulatory framework should not only support the development of RES but should also support the further development of the infrastructure needed

[2] *Available at: https://www.entsoe.eu/outlooks/offshore-development/*

to connect those assets to the rest of the grid. In this regard, EU institutions must ensure that the measures adopted at EU level are effectively implemented by Member States within a short period of time.

We recommend incorporating the respective rules and provisions for the acceleration of planning and permitting procedures, which are also relevant for electricity grids, of Council Regulation EU 2022/2577 to the revision of the RES Directive (REDIII/IV). Thereby, these provisions would apply for an indefinite period of time instead of being limited for period of 18 months.

Moreover, ensuring a full implementation of the current EU legislation and a stable and strengthened investment framework will be key enablers for the development of RES. Rapid development of renewables should be supported by the right market mechanisms, ensuring the most efficient dispatch and the right investment support tools, such that RES is exposed to the right market signals. Hence, changes to the electricity market design should focus on keeping the right dispatching signals (through capability based CfDs for example).

Question 30.2 Do you have additional comments?

No answer

Question 31 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?

A fully decarbonised, secure and integrated electricity system in 2050 will require an unprecedented scale of investments in new transmission capacity, including interconnections. Even if the uptake of complementary grid enhancing solutions can somewhat mitigate the need for capital and the need for smarter, OPEX-friendly regulation is obvious (cf. Q47), TSOs' activities are and will continue to be capital intensive and must be able to attract equity and debt. Tariff increases should be kept as low as possible. At the same time, regulatory frameworks should be sustainable with mechanisms that support sufficient remuneration to cover necessary costs including a reasonable return on capital invested.

The remuneration of costs of capital is not sufficiently taking into account the recent economic developments which will slow down the necessary investments for a swift grid expansion. ENTSO-E recommends that the new market circumstances with rising interest rates over the last months should lead to a revaluation of the regulated rate of return components (primarily risk-free rate, market-premium, and the cost of debt) to be carried out across national regulatory frameworks.

Furthermore, it would be advisable that national frameworks include remuneration for projects under construction. Given that permitting and other administrative processes result in a long lead-time between the initial investment decision and the asset being in operation, non-remuneration of assets under construction would require higher revenue stream over the lifetime of the asset to compensate for cost of capital in the construction period. In addition, additional costs may be necessary to address social acceptance and avoid project delays.

Besides, innovation in transmission assets should be considered in the remuneration frameworks covering the costs associated to digitalisation of new infrastructures. Future investments in transmission infrastructure are inevitably linked to an increase in operational expenditures (e.g. future offshore grid). Sufficient means should be ensured to remunerate the operation and maintenance of transmission infrastructure to maintain high quality of service.

A re-evaluation of the cap on the G-component in grid tariffs (i.e. charge for generators) should be considered, as all grid users should pay a fair share of grid costs. Dimensioning of the grid is becoming more related to (peak) generation and generation is more dispersed over all voltage levels of the network. A well-coordinated grid tariff for generation across the EU would establish a level playing field between production and demand response and would incentivise generators to efficiently use scarce transmission capacity. Connection charges should also reflect at least the customer specific costs.

Without prejudice to national prerogatives, tariff structures should incentivise efficient behaviour of generation and load to minimise the total costs of the electricity system, while keeping cost-reflectivity and fairness as guiding principles. Tariff structures should also be reviewed with the objective of making use of the available flexibility in the system. Stronger capacity components (kW), locational elements, and more dynamic time elements (e.g. a kW-peak component could be zero or discounted during non-congested periods to stimulate flexibility) will result in better cost-reflectiveness.

Finally, for cross-border RES connected through offshore hybrid projects, greater alignment of tariff practices should be assessed in order to provide a level playing field across countries and a clearer investment outlook for both transmission and generation.

ENTSO-E nonetheless believes that introducing any EU-wide rules on tariffs should be considered only after an in-depth impact assessment.

Subtopic: Limiting revenues of inframarginal generators

Question 32 Do you consider that some form of revenue limitation of inframarginal generators should be maintained?

No

Question 33 how do you rate a possible prolongation of the inframarginal revenue cap according to the following criteria:

0= Not at all preferable
10- Definitely preferable

(a) the effectiveness of the measure in terms of mitigating electricity price impacts for consumers no score

(b) its impact on decarbonisation no score

(c) security of supply no score

(d) investment signals no score

(e) legitimate expectations/legal risks no score

(f) fossil fuel consumption
no score

(g) cross border trade intra and extra EU no score

(h) distortion of competition in the markets no score

(i) implementation challenges no score

Question 34 Do you have additional comments? (

With regards to the criteria listed above to rate a possible prolongation of the current inframarginal revenue cap, we have chosen not to provide a scoring (as the numbering would also depend on other alternative policy options considered) instead offering some substantiated remarks:

- The current revenue cap doesn't per se impact consumer prices. Depending on its specific implementation (included generators, cap level and duration, exemptions, etc) it allows Member States to collect a variable amount of revenues that can then be redistributed to (some) consumers in different forms. By not directly affecting wholesale price formation it should not distort incentives for flexibility, demand response or energy savings. However, incentives for demand to react to prices can also be affected depending on how revenues are redistributed to consumers.
- In the long-run, negative effects on investment signals and investors' confidence have to be considered.

Taking a long-term perspective, to decarbonise the power system it is essential to strengthen investments signals for transmission/generation infrastructure and incentivising flexibility. Furthermore, additional mechanisms which compensate for reduced investment incentives imposed by revenue caps may be needed to compensate for the deteriorated investment framework.

- In terms of distortions, the revenue cap does not seem to impact the merit order and hence fossil fuel consumption. As per cross-border trade and competition, some distortions may be introduced by different implementation at national level (e.g. via technology-specific caps, accounting of hedging), especially in the long run if leading to investments being more advantageous in some countries vs. others.
- The implementation complexity also depends on specific national designs and specificities. However, the administrative burden and necessary data exchanges to manage or comply with such mechanism must not be underestimated.
- The legal framework supporting this mechanism could also be legally challenged, which would generate further uncertainty in the electricity market.

Lastly, from a security of supply perspective, ENTSO-E considers fundamental to ensure that the implementation of the revenue cap does not lead to distortions or decrease of liquidity in balancing markets which are essential to guarantee the stability of the system at the lowest cost for consumers.

Question 35 Should the modalities of such revenue limitation be open to Member States or be introduced in a uniform manner across the EU?

No answer

Question 35.1 Do you have additional comments?

No answer

Question 36 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?

No answer

ALTERNATIVES TO GAS TO KEEP THE ELECTRICITY SYSTEM IN BALANCE

Question 37 Do you consider the short-term markets are functioning well in terms of:

	Yes	No
(a) accurately reflecting underlying supply/demand fundamentals	X	
(b) encompassing sufficiently liquidity	X	
(c) ensuring a level playing field	X	
(d) efficient dispatch of generation assets	X	
(e) minimising costs for consumers		
(f) efficiently allocating electricity cross-border		

Question 38 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?

No

Question 38.1 If yes, please explain. If no, Do you have additional comments?

In the electricity market there is a constant need to match demand and supply to keep the system stable. However, as in other commodity markets, the principle of marginal pricing will secure the most efficient solution, dispatching the cheapest resources and incentivising flexibility.

Changing price rules will not solve structural market imperfections. As documented in academic literature and international experiences, alternative models to marginal pricing will at best lead to the same results, or more likely to inefficient market outcomes and/or perverse bidding incentives.

Alternative pricing mechanism would not ensure efficient use of cross border capacity. With marginal pricing, the prices in two bidding zones (BZ) reflect the costs of the most expensive resources in each BZ. Power flowing from one BZ to the other will then substitute the most expensive resource in the importing BZ, which truly reduces this BZ cost. Because the price in the exporting BZ reflects the cost of the most expensive unit there, it is ensured that the cost increase in the exporting BZ is less than the cost reduction in the importing BZ, increasing social welfare. With marginal pricing, this result is automatically obtained via the market clearing.

As per Q37 d & e above, we agree that price signals are essential to ensure an efficient dispatch, optimising the integrated energy system. However, short-term markets alone cannot minimise costs for consumers and need to be complemented by efficient investment signals, retail pricing solutions and effective public policies. To ensure dispatch efficiency it is important to properly reflect grid constraints: the current application of virtual capacity leading to redispatch has to be reconsidered. In the longer term, future network expansion and transition cost will need to be considered. Regulatory sandboxes should be allowed to integrate efficiently the use of remedial actions while avoiding undue discrimination between internal and cross-zonal exchanges.

Question 39 How can the EU emission trading system and carbon pricing incentivize the development of low carbon flexibility and storage?

No answer

Question 40 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)?

No

Question 40.1 Do you have additional comments?

Experience with the European SIDC shows great opportunities and flexibility for market participants to adapt their schedules in accordance with their best forecasts.

At the same time, the accelerating development of RES results in an increased demand for participation in the upcoming European Balancing Platforms or where this is not possible for shorter intraday gate closure time (ID GCT). In the future, shorter intraday gate closure times could be introduced where needed – subject to compatibly with operational constraints which also depend on different balancing approaches by TSOs.

In any case, it important to avoid including requirement on timings in a primary regulation, as these are better dealt via methodologies of CACM GL and EB GL. As such, we do not see a need for the market design reform to amend provisions on ID GCT in the current Electricity Regulation.

Reduction of the TSO's operational window to 15 min would make it necessary to ensure the availability of sufficient generation able to correct system imbalances in less than 15 min. Apart from being costly, this change may have a negative impact on emissions as the units able to provide such a service often have high emissions. Moreover, it should be noted that the current ID GCT for cross border trade is 60 minutes due to several technical reasons:

Need of sufficient time to nominate and match cross border nominations, determine target values for loadfrequency control, to manage any virtual capacity due to the 70% requirement, build-up grid models, analyse load flows and coordinate remedial actions.

For countries that participate in TERRE, this balancing platform requires GCT of 60 min. For other European balancing platforms, the GCT for BSPs to submit bids is at t-25 min. An ID GCT after the balancing GCT, would result in interference between ID and balancing markets.

Nevertheless, we acknowledge the right for individual TSOs to have shorter ID GCT within their own control area if considered beneficial.

Question 41 Do you consider that market operators should share their liquidity also for local markets that close after the cross-border intraday market?

No answer

Question 42 What would be the advantages and drawbacks of sharing liquidity in local markets after the closure of the cross-border intraday market?

The European power system can rely on an efficient and integrated cross border intraday market where liquidity has increased significantly since 2018. This is to the benefit of NEMOs, TSOs and market participants. In this market the order books from the NEMOs are shared and all orders are matched via the Shared Order Book (SOB).

In some bidding zones intraday trade is still possible within the bidding zone after the cross-border gate closure 60 min before operational hour. Currently order books are not shared between the NEMOs in the local markets the last 60 minutes. The arguments to share the liquidity also in local market is the same as in the pan European market. Increased liquidity leads increased efficiency. On the other hand some could argue that sharing liquidity could reduce the incentives for NEMOs to work on innovation.

In other bidding zones, where balancing markets already start after intraday cross-zonal gate closure time no split of liquidity takes place as remaining liquidity after European intraday is gathered and directly available in balancing markets and, when fully in place, will be made available to the European Balancing Platforms. The opening of balancing markets right after European Intraday market is very related to systems with high renewable energy penetration and pertaining to areas weakly interconnected with the rest of European Electricity system which require one hour lead-time for ensuring system security through balancing markets.

Question 43 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?

No answer

Question 44 What would be the advantages and drawbacks of such an approach?

High liquidity in the single European Day ahead market is important to get reliable prices. Prices which are also necessary for a well-functioning financial market. Currently the liquidity in the day ahead market is sufficiently high. Therefore, no specific requirements for traders or other measures are necessary.

If 2-sides CfDs become widespread, there should be strong incentives to parties with such CfDs to be in the spot market to hedge their positions, and then there should not be a problem to keep high liquidity. However, if by some reason we observe a drop in liquidity that raises concern about market functioning, further measures that give incentives to trade in the organised markets may be required, ultimately mandatory participation. When considering possible obligations to participate in day-ahead markets, it is important to ensure that liquidity in balancing market is also preserved as it's essential for ensuring system stability at the lowest cost for consumers.

Question 45 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)?

From a TSO point of view, detailed time and geographical granularity of information provided by market parties is critical to accurate forecasting and modelling of flexibility needs. This eventually makes planning and operational processes are leaner and more efficient thereby increasing security of supply and reducing related cost.
Market design must be able to better reflect the physical reality of the grid, e.g., through bidding zone reconfiguration, location dependent investment incentives for ancillary services, dispatch hubs, or nodal market design (where applicable).

With regards to day-ahead and intraday markets, locational information – which is essential for efficient congestion management – can also be compatible with portfolio bidding as long as there is a nomination by the balance service providers of the locational information regarding the activated or bid resources. This locational information may be supplied by including in the nomination made after the day-ahead and intraday markets how the portfolio schedule is shared between the corresponding physical units.

When it comes to the balancing markets, there could be benefits of more locational information, to facilitate the TSOs in balancing the system within its technical constraints. This is even more important close to real time, as there is little time left to correct activations that are in conflict the system needs and requirements. If you apply unit-based bidding, there is also an advantage that balancing bids can be used for congestion management where relevant. A challenge here is that the TSO may need a lot of data and advanced planning process to be able to adhere to all local constraints on the activated units. This may be easier to address when activations are allowed on a plant instead of unit basis, or in a small uncongested part of the grid.

Question 46 What further aspects of the market design could enhance the development of flexibility assets such as demand response and energy storage?

- Auctions for hybrid assets, where variable RES are combined with storage to be able to provide more stable supply profiles.

- In the longer run, stronger locational & temporal signals would give better opportunities for both demand response (DR) and storage to value their flexibility. The right responses in the right locations and time would also be beneficial for system operation. Locational & temporal signals have the potential to unlock the wide range of sources of flexibility by providing stronger incentives for dispatching and for siting of e.g. electrolysers, storage, DR, ensuring that they react in line with system needs. The most efficient solution will differ depending on future scenarios and on regional/national specificities. As a result, different levels of spatial granularity may be applied across the EU while ensuring the preservation of the IEM.
- Where the current market framework is insufficient to timely develop storage capabilities, alternative market mechanisms providing LT investment signals could be explored.
- Remove technical and regulatory barriers for DR to participate in energy, ancillary services, congestion management and capacity markets. Regulation should foster consumer participation and allow competition behind the meter with the use of sub-meters, providing a generic model for allocation of energy among market parties, and enabling consumers to provide flexibility for all services, via all technologies, at all voltage levels.
- Capacity subscriptions could facilitate smart load modulation during system scarcity, remunerating flexible consumers, reducing overall system costs to ensure adequacy, and establishing a price for capacity based on individual consumers' preferences.
- Fixed price contracts with fixed volumes (cf. Q57) - where the difference between the profiled contract volume and the actual consumption is settled at the spot price - ensure consumer protection while retaining incentives for flexible consumption.

Question 47 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?

Yes

Question 47.1 Do you have additional comments?

First, it should be noted that different regulatory regimes coexist in Europe regarding the treatment of balancing and congestion management costs, which are treated in some countries as OPEX for TSOs, and elsewhere as electricity system costs. In both cases ENTSO-E supports setting appropriate incentives to achieve cost efficiency and value for end-consumers.

The use of efficient and innovative solutions that lead to smarter use of the grid should be better incentivised, to complement the vast investments in the physical grid that are necessary to reach the EU's climate neutrality goals.

ENTSO-E observes there is widespread and structural under-remuneration of these. In many cases, TSOs do not even get full recovery of these, in particular for cross-border projects delivering substantial value to society (e.g. operating costs of European Platforms) and maintenance costs arising from the construction of network assets for system security (e.g. load flow-controlling equipment).

ENTSO-E has identified several recommendations to move remuneration models towards greater technological neutrality and more efficient use of the infrastructure:

a. Remuneration for end-of-life maintenance: when technically feasible, TSOs should be encouraged to prolong the economic lifetime of assets which can lead to significant cost savings and resources for society , as current frameworks often incentivize re-investments or out-of-pocket maintenance.

b. Market facilitation incentive: TSOs should be fully reimbursed for improving market services and preferably be financially incentivized by allowing to share in the benefits.

Finally, regulatory frameworks should give much stronger incentives to TSO spending in innovation and digitalisation and should encourage (economic) risk-taking. ENTSO-E's paper on innovation uptake (June 2022) outlines several key recommendations. Regulatory frameworks should notably include more outputbased innovation incentives (e.g., based on smart KPIs).

Question 48 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?

Yes

Question 48.1 If yes or no, Do you have additional comments?

Sub-metering is beneficial not only for settlement/billing and observability of demand response but for all different types of services an active consumer might wish to contract. Submetering with correct allocation rules and proper data access rules would allow active consumers to sell their flexibility to the markets, participate to energy communities, proceed to energy sharing or P2P transactions, contract different suppliers for different appliances behind the main meter, or to offer services to TSOs and DSOs.

For explicit demand response and certain flexibility services, the use of metering data from submeters for settlement purposes should be allowed, to allow competition behind the meter. DSOs should exchange with TSOs all the operational data of assets connected to their grid (also for units smaller than 10MW).
At the same time, full smart meter roll-out and billing based on market time units will be a key prerequisite for reflecting more accurately the dynamic value of electricity, thus facilitating large-scale implicit demand response.

However, "main" meters are not always sufficiently accurate or "granular" to measure the service that is provided by units behind the meter. The capabilities of flexibility resources behind the main meters are increasingly used by TSOs. To support these developments, clearer rules should be determined to favour participation of flexible resources behind the main meter, without compromising the overall safety of the power system. In particular, new rules (preferably at national level) will need to define roles and responsibilities (meter operator, metering point administrator/data responsible/data administrator) in relation to sub-meters, while ensuring interoperability as well as and non-discriminatory and transparent procedures for access to metering and consumption data.

Question 49 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?

Yes

Question 49.1 If yes or no, Do you have additional comments?

As a target, demand response (DR) needs to participate through aggregation or directly in the existing DA, ID and balancing markets, as well as congestion management, to support existing liquidity. In case a dedicated product is developed, it should be complementary to existing standard balancing products and not interfere with other balancing products.
Yet, as a transitory model and if well designed, a specific DR product for ancillary services or adequacy may help bringing into the market flexibility assets that would otherwise not yet participate. Such technologyspecific approaches should be mostly targeted at kick-starting DR, until it is fully integrated in the market.

A guiding principle should be to keep the energy market (DA, ID) as the cornerstone for dispatch signals to all kinds of assets (DR, generation or storage). In this context, DR should be progressively fostered through price signals such as time-varying tariffs or exposure to dynamic prices (or fixed price fixed volume contracts, cf. Q 46 & Q 57) thereby triggering an efficient usage of flexible technologies already in the energy market, limiting the volumes that would be adjusted in a dedicated ancillary service and thus respecting the proportionality principle.

Technologically, the rollout of smart meters and the usage of sub-meters (or fulfilling legal requirements (MID) metering devices embedded in electrical assets) are enablers for a faster adoption of DR in both energy markets and ancillary services markets. From a regulatory perspective, the upcoming DR Network Code could be used to specify rules of sub-meter usage.

Finally, dedicated market mechanisms for energy storage and dispatchable capacity could be complementary to ancillary services by DR. The former incentivize the realization of CAPEX-intensive assets, while the latter service enable a better usage of flexible assets whose primary purpose is to serve a final use (EVs).

Question 50 Do you consider that some form of demand response requirements that would apply in periods of crisis should be introduced into the Electricity Regulation?

No

Question 50.1 If yes or no, Do you have additional comments?

We do not need demand response in periods of crisis but at all times. To ensure the availability of demand response also during crises, the main task ahead is therefore to ensure its rapid development in all relevant markets. This will make demand response available also during crises, avoiding the necessity of specific requirements. At the same time, coherence with the Risk Preparedness regime must be ensured. Moreover, it is not necessary to put a formal requirement for demand response in the Electricity Regulation, as long as Member States have the possibility to introduce such requirements in periods of crisis.

The current energy crisis has shown that consumers are prepared to adapt their consumption behaviour but are often lacking clear or timely signals. Smart meters are a key enabler: their roll-out shall be accelerated where it is lagging behind.

But even consumers without smart meters can be engaged through broad-based communication for specific events of limited duration. Communication campaigns could become ordinary instruments that governments or TSOs and DSOs can trigger in moments of exceptionally low renewable generation and/or peak load, incentivising domestic consumers and small businesses to contribute to system security.

To ensure the availability of demand response, we see a number of possible measures:

- Member States shall provide an updated roadmap for the deployment of smart meters as well as clarify the framework for the use of certified sub-meters.
- A dedicated body (power exchange, TSO, NRA or other) shall publish or enable the publication of prices on the electricity forward and spot markets (at least day-ahead) free of charge.
- Further use of interruptibility schemes.
- Member states should be encouraged to implement measures for broad-based communication towards electricity consumers ahead of specific critical events of limited duration.
- In the longer term, investments in flexible industrial processes and/or smart buildings energy management should also be incentivized to develop flexible demand response.

Question 51 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?

Yes

Question 51.1 If yes, what would that be?

Auctions for hybrid assets (RES+storage) are also relevant in the short term (Q46). Furthermore, we suggest the following:

- A long-term assessment of flexibility system needs will provide a basis for market parties to accelerate investments and R&D in relevant technologies fitting such needs.
- Establish new, tailor-made ancillary services for both frequency and non-frequency needs of the system. Need of more flexible regulatory requirements for defining and applying specific balancing services products.
- Accelerate smart meter rollout so to deploy them everywhere, to enable efficient demand response and local storage facilities.
- Allow the use of submetering and competition behind the meter, so to isolate the inflexible and/or essential consumption (which can be subject to fixed price contracts) from the flexible appliances (e.g. EVs), which can be exposed to dynamic price signals.
- Expose as many consumers as feasible to dynamic prices, while also offering hedging tools to limit their exposure (fixed price fixed volume contracts in Q46). This should also be accompanied by better information to consumers about benefits & risks of dynamic prices and about energy saving measures.
- Where the current market framework is insufficient to timely develop storage capabilities, alternative market mechanisms providing LT investment signals could be explored.
- Modify Measuring Instruments Directive to include improvement of smart meters technology and remove barrier for embedded measuring equipment (Q46).
- Explicitly exempting ancillary services markets from the EU Directive on Public Procurement. As the integration of balancing markets progresses, and as flexibility services are procured in an increasingly dynamic manner, (e.g. via auction platforms) such procurement constraints are not fit for purpose - as they result in lengthy and burdensome process - and redundant considering regular monitoring TSOs are subject to by NRAs.

Question 52 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?

No

Capacity mechanisms are likely to be necessary in most EU countries as a standard feature of well-functioning wholesale markets to ensure system adequacy. At the same time, CRM design should be consistent with need to accelerate decarbonization of the power system and to avoid lock-in effects of fossil fuel technologies beyond their necessary contribution to adequacy.

Today, CRMs are considered by EU regulation as a last resort measure and are subject to strict pre-requisites and cumbersome and lengthy approval processes. The upcoming market design reform is an opportunity to introduce targeted improvements to the regulatory framework to:

1) Recognise the structural need of long-term investment signals in national market designs to ensure overall system and resource adequacy while achieving EU long-term policy objectives;
2) Facilitate Member States' introduction or amendment of capacity mechanisms through faster, clearer and more fit-for-purpose approval processes;
3) Improve consistency and regional/EU coordination of capacity mechanisms and related applications of EU reliability standards by promoting best-practices and high-level design principles.

Concretely, considering CRMs as a possible structural element of national markets implies that the control of such a measure by the European Commission (assessment of compatibility under the state aid regime), based on the CEEAG and verifying the requirements of Regulation 2019/943 are met, should be significantly limited since it would by default be considered compliant with the EU target market design. The European Commission's assessment could then be primarily focused on ensuring that the design of CRMs avoids market or cross-border distortions Since timing is also key to solve adequacy issues, CRM approval should be framed into a reasonable and reduced delay to avoid a too long delay between the decision of the MS and its actual implementation. The approval process should primarily focus on a proper design, rather than the elaborate justification for introducing the mechanism or a Member State's discretionary and strategic choice for a capacity mechanism as an enabler for the energy transition, increased energy independence or other policy objectives.

Regulation should allow National adequacy assessments to further complement the ERAA in assessing system adequacy more holistically, with a higher granularity and dedicated sensitivities, for instance addressing locational adequacy issues. The phase-out of conventional generation also requires considering local capacity compensation needs and ancillary services availability both in system adequacy assessment and in CRM design. Most importantly, today's governance process for ERAA approval needs a fundamental review with an approval process that looks beyond only CRMs and is more inclusive to Member State views.

While CRMs should be designed taking into account the energy transition objectives, we believe that a full integration of policy objectives in the CRM should not be required. In fact, other market mechanisms may be more suitable to support specific objectives or technologies such as storage (see for instance dedicated auctions for storage assets being considered in Italy).

It is important the CRMs valorize the contribution of different technologies to their respective contribution to adequacy. While existing CRMs already allow participation of demand response and storage, future designs should enable them to participate to the full extent possible.

Considering the need to quickly adapt the design of electricity markets to make them fit with the long-term policy goals, the cumulative conditions that do make capacity mechanisms instruments of last resort, once all other options have been exhausted, should be carefully reconsidered.

Question 53 Do you see a benefit in a long-term shift of the European electricity market to more granular locational pricing?

Yes

Question 53.1 Do you have additional comments?

The topic of market granularity deserves an in-depth assessment and discussion which we would welcome, but that we do not see feasible in the desired timeline of the market design reform of 2023-2024. In this assessment, the outcome of the ongoing bidding zone should also be taken into account.

Stronger locational signals will improve quality of price incentives provided to the market participants making them more aligned with real-time system state and/or longer-term investment needs in ancillary services and back-up generation capacity. This will better bridge the gap between market and physics. This will allow for reduction of the tariff-payers' costs related to resolving system constrains, which are expected to increase as an effect of going towards net-zero generation and more volatile and dynamic system. Due to significantly increased volatility of generation, load and flows patterns as well as rapid investment in new resources, the constraints problems cannot be efficiently solved only by grid reinforcements but needs to be complemented with electricity generation, demand and ancillary services at the right locations.

On the other hand, shifting to more granular locational pricing leads to challenges concerning liquidity, regulatory stability, and transition costs. These are to be taken into account, when performing a holistic assessment.

There are several options of increasing locational price signals: improved bidding zone configuration, integrating so-called "dispatch hubs" in the market coupling, nodal market design (where applicable), and location dependent investment incentives also considering ancillary services. The most efficient solution will differ depending on future scenarios (e.g., pace of grid infrastructure development) and on regional/national specificities such as grid structure and congestions. As a result, different levels of spatial granularity may be applied across the EU while ensuring the preservation of market integration.Whichever market design option is chosen, it should not only have benefits that exceed implementation costs but ensure that the integrated European electricity markets seamlessly work together.

BETTER CONSUMER EMPOWERMENT AND PROTECTION

Energy sharing and demand response

Question 54 Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?

No answer

Question 54.1 Do you have additional comments?

No answer

Question 55 If such a right were introduced:

(a) Would it affect the location of new renewable generation facilities?
No answer

Do you have additional comments?
No answer

(b) Should it be restricted to local areas?
No answer

Do you have additional comments?
No answer

(c) Should it apply across the Member State/control/zone?
No answer

If yes, why and what should happen if bidding zones are changed?
No answer

Do you have additional comments?
No answer

Question 56 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?

Yes

Question 56.1 If yes, what particular issues should be taken into account?

For consumers, unlocking flexibility from behind the meter devices (e.g. heat pumps, electric vehicles, storage devices) will bring significant benefits thanks to new energy services tailored to their needs, allowing to combine them with "standard" supply contracts for their non-flexible share of consumption. For explicit demand response and certain flexibility services, the use of submeters should be allowed so to lower entry barriers for flexibility providers and allow competition behind the meter. At the same time, full smart meter roll-out and Imbalance Settlement Period-based billing will be a key prerequisite for reflecting more accurately the dynamic value of electricity, thus facilitating large-scale implicit demand response.

To support these developments, clearer rules should be determined to favour participation of flexible resources behind the main meters. These resources must respect technical limitations in the relevant grid and ensure the overall safety of the power system.

ENTSO-E's supports the use of submeter data to promote the emergence of flexibility actors. Depending on the service provided, it's necessary to define if/how a sub-meter should be qualified as a certified meter, providing relevant measures, depending on its use (in real-time or not, for prequalification, for baseline or for settlement…). In particular, new rules (preferably at national level) will need to define roles and responsibilities (meter operator, metering point administrator/data responsible/data administrator) in relation to sub-meters, while ensuring interoperability and non-discriminatory and transparent procedures for access to metering and consumption data.

Question 56.2 Do you have additional comments?

Full smart meter roll-out is crucial to fully enable demand response and will also support the submetering concept. Smart meter installed in grid access point (connection point) allows for correct planning (i.e. baseline calculation), settlement and billing of all the services for customers as well as for verification / fraud prevention of sub-metering data.

It should be emphasized that the use of sub-metering for settlement purposes is justified only in the case of applying dedicated tariffs and settlement rules for specific devices in the customer's network (e.g. charging stations) or when the customer provides services based on these devices that require specific settlements.

In the case of using metering data from sub-meters for settlement, they should meet the requirements as for certified meters (meters installed by DSO/TSO in the grid connection point).

Regardless of the above, in accordance with the new regulation that is being prepared on interoperability requirements and non-discriminatory and transparent procedures for access to metering and consumption data, it will be necessary to define (preferably at the national level) role which entities will play in relation to sub-meters.

In addition, taking into account the fact that the sub-meter will be installed inside the customer's installation, access to which may be limited for meter operator, measures to reduce the risk of fraud on the part of the customer should be taken into account.

Considering the above conditions, it is proposed that at the level of the Member States a Cost-benefit analysis covering the national conditions of the implementation of sub-meters shall be developed.

Offers and contracts

Question 57 Would you support provisions requiring suppliers to offer fixed price fixed term contracts (ie. which they cannot amend) for households?

No

Question 57.1 Do you have additional comments?

We don't believe an obligation on suppliers to offer fixed price contract would be of a great benefit. Forcing them to offer fixed price contracts would impact the business process and costs of such suppliers, with negative impact on competition in the retail market which may ultimately increase costs for consumers.

As end-consumer flexibility will be key in a system with increased volatility, fixed price contracts should be combined with tools and offers to complement risk hedging with effective incentives for valuing flexibility, especially from consumers and assets that have such flexibility potential.
Allowing competition behind the meter via sub-metering (as developed in question 56), allows flexible assets being exposed to short term signals. It is positive for the consumers as it will allow benefiting from low prices at times of

high RES generation, and it is positive for the system as the flexible part of the load will tend to follow RES generation variation.

Alternatively, and where submetering would not yet be available, a particular type of fixed price contract would be worth promoting: contracts with fixed prices for a pre-defined volume. In these contracts, surplus/deficit consumption compared to the contractual volume - distributed across the year according to a pre-determined profile - is settled at the spot price. This option is in nowadays a common contract for industrial and commercial customers, but not (yet) for households. With appropriate support and awareness, it could be suitable also for households, especially the most flexible ones. Such contracts offer an attractive balance between consumer protection on the one hand and exposure to dynamic pricing on the other hand. As such, it could prove an important tool to ensure social acceptance of demand flexibility.

Question 58 If such an obligation were implemented what should the minimum fixed term be?

No answer

Options available:

a) Less than one year
b) one year
c) longer than one year
d) other

Question 58.1 If "Other" please specify. Otherwise, Do you have additional comments? maximum)

No answer

Question 59 Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts:

No answer

	Yes	No
(a) Should these provisions be clarified?		
(b) If these provisions are clarified should national regulatory authorities establish ex ante approved termination fees?		

Question 59.1 Do you have additional comments?

No answer

Question 60 Do you see scope for a clarification and possible stronger enforcement of consumer rights in relation to electricity?

No answer

Question 60.1 Do you have additional comments?

No answer

Prudential supplier obligations

Question 61 Would you support the establishment of prudential obligations on suppliers to ensure they are adequately hedged?

No answer

Question 62 Would such supplier obligations need to be differentiated for small suppliers and energy communities?

No answer

Supplier of last resort

Question 63 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? (

No answer

Question 64 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?

No answer

Question 64.1 (a) If such a provision were established, should price regulation be limited in time and to essential energy needs only?

No answer

Question 64.2 (b) Table

No answer

	Yes	No
Would such provisions substitute on long term basis for direct access to renewable energy or for energy efficiency?		
Can this be mitigated?		

Question 64.3 (c) Table

No answer

	Yes	No
Would such contracts reduce incentives to reduce consumption at peak times?		
Can this be mitigated?		

Question 65 Do you have additional comments?

Member States should implement policies and tools to partially shield less flexible, energy intensive, or more vulnerable consumers from unlimited exposures to possible extreme or sudden retail prices increases**.** These should primarily include direct support of consumers while not removing incentives for demand response, energy savings, flexibility, storage, or energy efficiency nor distorting wholesale market functioning.

ENHANCING THE INTEGRITY AND TRANSPARENCY OF THE ENERGY MARKET

Question 66 What improvements into the REMIT framework do you consider as most important to be addressed immediately?

- The regulation could benefit from clear and updated definitions of wholesale energy market and wholesale energy product (e.g., should capacity market be considered as a wholesale market?)
- The regulation could benefit from a clear definition on what is considered inside information.
- Comprehensive market surveillance requires access to complete market data; therefore, it should be performed by ACER and NRA that have an overview over all markets and only supplemented by surveillance efforts performed by Persons Professionally Arranging Transactions (PPATs). Surveillance performed by PPATs should not be used as a main tool of detection of market abuses. Monitoring capacities to be better utilized by ACER while investigation and enforcement must remain at national level.
- Ensure that there are no regulatory gaps in the market monitoring between the physical and financial markets (derivative-markets).
- Improving efficiency in market monitoring by enhancing consistency between the Transparency Regulation and REMIT. Firstly, it should be clear that publishing given information on the Transparency Platform (TP) in accordance with the Transparency regulation implies it does not have to be published again on an Inside Information Platform (IIP) in order to comply with REMIT. Secondly, the scope of TP publications should be updated to reflect current system dynamics (e.g. smaller thresholds for generators' publications).
- Current requirements in ACER guidance regarding Inside information publications are not optimal; as the Market Participants are responsible for publications but required to do it via Inside Information Platforms (IIP). The way liability is shared between IIP and Market participants (MPs) is unclear and require clarification for better efficiency.

Question 67 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?

- Clarify the notions of market manipulation and insider trading. Be prescriptive vis-à-vis known malfeasance to put under surveillance.
- Comprehensive monitoring of the entire market with overview of markets and market players activities. Fragmentation, and possible gaps in roles and responsibilities to be avoided between markets, parties, and jurisdictions. Improvements on the accessibility of information cross border and 'cross products' for efficient market monitoring. Provide clear guidance on cross-border monitoring coordination processes between PPATs.
- Enforcement power should remain on national level with the responsible National Regulatory Authority.

Question 68 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?

- We recommend that all relevant data related to prices and volumes traded from all parties should be published and available. A good example is ENTSO-E Transparency platform which publishes free of charge relevant data in interoperable formats, and across all wholesale markets and products.
- Implementing regulation 1348/2014 does not refer to the IIPs, but to the website of a market participant. To address these shortcomings, we recommend a single point for publication and communication of data and information. The concept of IIPs should be revisited with a solid regulatory impact assessment, including whether it has a sufficient legal basis in the light of the associated costs.
- Regarding the XML schema mapping of reporting table should be extended to TSOs. Currently, the parameters to be specified are too much tailored to producers. (e.g., The existing requirements to report unavailable capacity as inside information on an Inside information platform is not aligned with the requirements on publication of unavailable transmission capacity set out in the transparency regulation (EU Reg. 543/2013) which is considered fundamental data reporting under REMIT.)
- The publication of insider information should be possible as time series.
- For reporting insider information, the date and time of the first submission and revisions of the information should be made accessible.