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European Commission consultation on market design – EPEX SPOT reply paper

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○ Subtopic: Power Purchase Agreements (PPAs)

Q1. 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]

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

1. Regulatory risk: The current crisis has led to structural market interventions (e.g., inframarginal revenue claw-back) resulting in significant market uncertainty, thereby reducing the volume of contracted PPAs. With stabilizing market conditions, the PPA uptake is increasing again, as demonstrated by the latest conclusion of two long-term hedges executed in EEX's Spanish Power Futures (from CAL-27 to CAL-31), totaling 1.1TWh shows.
2. Permitting: regulatory complexity, uncertainty, lengthy procedures, investors discouragement, projects delay, costs increase.
3. National subsidy schemes for competitive renewable energy sources (such as two-way state backed CfDs) limit the PPA market to become more mature.
4. Lack of knowledge with developers& investors on the possibilities of existing market instruments to hedge their risks: e.g., price risk, volume risk, counterparty risks can be hedged via existing trading products & clearing on energy exchanges & central counterparties.
5. Need to strengthen and facilitate market-based platforms already in existence providing small- & medium sized actors with access to PPAs (e.g., increasing standardization and transparency).
6. Need for liquidity support for risk management of PPAs: initial margin requirements for long-term PPA hedges were stable at 3-7% in terms of notional value before the current supply crisis.
7. Adverse effects from IFRS accounting rules: depending on design, PPAs are classified as financial instruments consequently leading to further requirements under financial regulation (MiFID II) & financial accounting standards (IFRS). This can lead to additional reporting obligations up to adverse financial ratings as a PPA is rated as a long-term obligation in the profit & loss statement of a company.
8. Regulatory barriers affecting the transfer of GOs to off-takers. E.g., it would be beneficial to harmonize rules for the use of GOs across countries and support the development of reliable GO-systems in third countries.

Q3. Do you consider that the following measures would be effective in strengthening the roll-out of PPAs: *[at most 6 choice(s)]*

(a) pooling demand in order to give access to smaller final customers, *[YES]*

(b) providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks), *[YES]*

(c) promoting State-supported schemes that can be combined with PPAs *[NO]*

(d) supporting the standardization of contracts, *[YES]*

(e) requiring suppliers to procure a predefined share of their consumers' energy through PPAs, *[NO]*

(f) facilitating cross-border PPAs. *[YES]*

Under normal market circumstances with lower regulatory uncertainty, PPAs have proven themselves as an important hedging tool. PPAs are a crucial building block for utilities to hedge their risk exposure adequately in combination with other market-based instruments. It is therefore of outmost importance to ensure regulatory stability and evaluate different market-based hedging options in detail with market participants to identify further potential improvements.

(a) Promote the availability of experienced intermediaries that already today provide pooling and risk-management services to small- and medium sized market participants. Furthermore, small- and medium sized market participants should be further educated on already existing options for a market-based risk management.

(b) Market participants should make usage of already existing market-based instruments to protect them against potential risks.

(c) State-support schemes should possibly not interfere with market based PPAs as this would likely result in market distortions.

(d) An increased standardization of smaller PPAs would positively result in the product being more tradeable as well as result in a more efficient conclusion of PPAs. The more standardized products become the better they can be traded and would be more efficient to conclude.

(e) Suppliers should not be required to procure a pre-defined share of their consumers' energy through PPAs. Market participants with an adequate hedging culture should make free-usage of market-based hedging instruments to optimally hedge their individual risk profile.

(f) Cross-border PPAs should be further facilitated by investing into sufficient cross-border transmission capacities as well as further harmonization of the regulatory framework.

Q4. In addition to the options proposed in question 3, do you see other ways in which the use of PPA for new private investments can be strengthened via a revision of the current electricity market framework?

[YES]

i. Regulatory risk: the current crisis has led to structural market interventions (e.g., inframarginal revenue clawback) resulting in significant market uncertainty, thereby reducing the volume of contracted PPAs. With stabilizing market conditions, PPA uptake is currently increasing again, as the latest conclusion of two long-term hedges executed in EEX' Spanish Power Futures (from CAL-27 to CAL-31), totalling 1.1TWh shows.

ii. Already today, EEX lists power futures for 20 European markets. In addition, EEX extended yearly futures to CAL+10 in markets with high potential of PPA activity (DE, ES & IT), to facilitate long-term hedging and provide an additional market-based instrument to strengthen PPA development.

iii. Member states should refrain from unnecessary structural market interventions and especially avoid that already implemented clawback mechanisms, such as the inframarginal revenue caps, are prolonged. Uncoordinated structural market interventions lead to significant uncertainty and further distort investors' confidence. As a result, and within the overall high-level of uncertainty due to the ongoing energy supply crisis, such mechanisms further limit the willingness of investors to engage in long-term contracts such as PPAs.

Q5. Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity?

[YES]

In general, the underlying principle should be freedom of choice. It is of outmost importance that market participants can identify and make use of the most adequate hedging solution in accordance with their respective risk profile. Already today, most generators follow an adequate hedging strategy by hedging large parts of their revenues well in advance. In addition, and as the market evolves, the level of sophistication of RES investors will further increase making them more accustomed to the usage of market-based risk management instruments such as PPAs and financial derivatives.

Q6. 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]

Q7. Do you consider that increasing the uptake of PPAs would entail risks as regards: *[YES/NO for each aspect below]*

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

(a) It depends on the specificities of the individual PPA. Virtual and financial PPAs are based on a strike price agreed upon in the spot market and therefore still allow the flow of volumes into the latter. Purely physical PPA with direct delivery indeed entails the risk to cannibalise the short-term market.

(b) Small- and medium sized actors can currently gain sufficient access to PPAs via intermediaries. We see these conditions further improving with an additional up-take of PPAs. Standardization will further increase allowing small- and medium size actors to better understand and conclude PPAs. An increasing liquidity within the PPA market eases the process of market participants to find their adequate counterparts and reducing overall transaction costs.

(c) No but, the regulatory framework for PPAs needs to be harmonized on a European level. The more regulatory complexity and uncertainty there is, the harder it will be for PPAs to evolve.

(d) PPAs are an important market-based cornerstone to promote the roll-out of renewables.

(e) PPAs contribute to risk management and stability of revenues and costs.

○ Subtopic: Forward Markets

Q1. 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]

Q2. Do you consider that the liquidity in forward markets is currently sufficient to meet this objective?

[YES]

In general, and under the current framework conditions, forward hedging is a highly efficient way to mitigate exposure to short-term volatility. At European level, the liquidity between BZs may vary, but being a financial market, this does not necessarily lead to an inability for market participants to properly hedge themselves in the forward market. Even in the absence of a well-functioning and liquid secondary market for LTTRs, location spread products offered by exchanges can be traded in a continuous manner complementing the continuous nature of electricity trading. Already today, forward hedging is a highly efficient way to mitigate exposure to short-term volatility and should remain the primary hedging instrument. Against this background, we welcome targeted improvements on the basis of a detailed impact assessment, to further strengthen the core functions of electricity forward markets to protect consumers and ensure that electricity markets can support the decarbonisation of the energy system.

Moreover, targeted improvements to increase the liquidity of forward markets are needed. European countries need to maximise the amount of new supply brought onto the energy system to make up for the supply shortages as quickly as possible and increase the overall security of supply. Investments in these new generation capacities need to be secured.

Q3. In your view, what prevents participants from entering into forward contracts?

Causes of liquidity issues can largely differ between different bidding zones. A generalization of problems in the forward market across bidding zones does not reflect this complexity in an adequate manner. National interventions measures hindering the building up of liquidity in certain bidding zones, such as subsidies on fossil, renewable and nuclear investments or regulated tariffs should be tackled with priority. In the absence of a well-functioning and liquid secondary market for LTTRs, location spread products offered by exchanges can be traded in a continuous manner complementing the continuous nature of electricity trading.

Q4. In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?

[NO]

In general, market participants should be able to freely decide on the appropriate management of their risks, but incentives to follow an adequate hedging culture should be provided. Requiring electricity suppliers to hedge a certain share of their supply could ultimately lead to higher electricity prices for consumers as suppliers will incur additional costs they may have otherwise chosen to avoid. Increased hedging would indeed have a positive impact on reducing price volatility. However, this should not be imposed as an obligation. Furthermore, a lesson learned of the recent crisis was that being hedged would have been the better choice. Hence, there is a natural incentive to be hedged in the future to avoid negative consequences in case of a returning price volatility.

Q5. Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets?

[NO]

To provide adequate solutions to the functioning of the forward market, it is crucial to analyze in detail the specificities hampering liquidity in the respective bidding zones. While in theory the virtual hub option may seem like a potential solution, it is disconnected from the physical realities of the underlying spot markets and an improper hedging instrument to manage basis risk. A hub with liquid transmission rights does not solve the problem as:

1. The transmission rights between the hub and a smaller zone within the hub will remain illiquid, since the same market participants that are interested/not interested in trading the smaller zone will be interested/not interested in trading the transmission rights. Any program to make these transmission rights more liquid can also be applied to the small zone in the first place. Thus, creating a hub with transmission rights only transforms the problem without solving it, at the expense of turning market structures upside-down.
2. There is no spot market that corresponds to the hub. However, it is the strong connection of physical spot markets and derivative trading that creates a perfect hedge to these spot markets that drives liquidity in these derivatives. This means that the hub market might turn out to be relatively illiquid.
3. There is no reason why market participants should prefer a hub over a liquid neighboring market. If we take the example of the German bidding zone: market participants based in Germany will have little incentives to trade a hub containing Germany. A hub containing Germany will therefore lack a large amount of liquidity and will likely be less liquid than the German bidding zone. Neighboring markets must therefore have a strong preference for the hub price compared to the German price to trade the hub instead of the German market. Such strong preference can only arise if the hub price is sufficiently different from the German price on a yearly average. As of today, this seems unlikely.

Q6. Do you have experience with the existing virtual hubs in the Nordic countries?

*[*In case you have experience with the existing virtual hubs in the Nordic countries, how do you rate this experience? *Very negative/Very positive. In case you don't, do you have additional comments related to the existing virtual hubs in the Nordic countries?]*

[YES]. Rating = 2

While in theory this option may seem like a potential solution, it is disconnected from the physical realities of the market. This can be seen if we look at the Nordic market. In the past, in times where there was limited congestion, the model did not show any deficiencies. But after splitting the Nordic market into different bidding zones, this hub no longer allows for a proper hedge. Consequently, the trading volumes in the Nordics have experienced a continuous downtrend over the last years, resulting in a current overall market volume which is less than half the size compared to 5 years ago. Furthermore, the solution is not neutral to bidding zone reconfigurations. The liquidity of the reconfigured bidding zone would be affected just as much as without the hub configuration. Finally, the Zone-to-Hub option leads to liquidity issues being shifted to the Hub-to-Zone risk. Market participants will therefore continue to have exposures in individual bidding zones.

Q7. 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?

i. Enhance predictability of market design to allow market participants to enter long-term hedging positions and make use of already existing products (e.g., EEX Cal+10).

ii. Refrain from structural market intervening policies (e.g., Iberian exception) increasing uncertainty and consequently decreasing forward market liquidity.
iii. Avoid market-distortive subsidies for competitive technologies reducing competitive pressure thereby minimizing demand for market-based hedging.
iv. Improve conditions for PPAs by strengthening existing platforms (e.g., Pexapark), providing sufficient transmission capacity in power networks and speeding up permitting procedures.
v. Use already existing instruments such as locational spread products offered by exchanges to increase forward market liquidity.
vi. Weigh bidding zone configuration against market harm such as a loss in liquidity.

In addition to improvements in the electricity market framework further aspects in clearing and settlement of forward markets could foster further development of forward markets:

a. Broaden the pool of eligible collateral under the European Market Infrastructure Regulation (Regulation (EU) 648/2012) for improved flexibility in meeting margin requirements.
b. Support access to financing of margin requirements in exceptional market situations to allow continued hedging when it is needed most.

○ Subtopic: Contracts for Difference (CfDs)

Q1. 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)?

[NO]

The mechanism behind contracts for difference covering fluctuations against an underlying asset is not new in energy trading. Derivatives market contracts are used to hedge a price. However, the decisive difference compared with the present discussion regarding the introduction of state-backed CfDs is that trading participants assume the risks involved in their contracts. But, at present, advocates of this instrument for RES funding only via means of two-way state-backed CfDs suggest that the states bear the full risk of private investments, when already market-based instruments (such as hedging instruments) can allow generators and consumers to limit a great part of their risk exposure. While some CfDs – carefully designed and tailored to specific contexts and markets – might show some benefits (i.e., increasing the overall security of supply), the introduction of widespread and mandatory state-backed two-sided CfDs for the RES expansion could constitute a break with the approach of gradual market integration of all types of generation, which has been developed and implemented over many years. A fundamental change to the funding system would undermine the strength of the market price signal. The prices determined on the wholesale market are important indicators for scarcity in the power system both in the short- and long-term perspective, and can act as references able to improve liquidity. Wholesale market prices are the impulses for generation, consumption, hedging, flexibility and act as a driver for innovation. These incentives coordinate the power market and are indispensable for the energy transition. Finally, CfDs might be suitable for RES support, but they should not be extended to all generation types, otherwise the energy market could lose its role in dispatching the least expensive units first.

Q2. 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?

[NO]

To speed up the roll-out of renewables and ensure the minimization of costs on the end-consumers, market ready renewable technologies need to be fully integrated into the market to contribute and to be exposed to an efficient price signal. Fully market integrated renewables are both necessary and feasible. It is the interest of the end-consumer that subsidies for mature technologies are avoided. Investment grants for immature technologies, situated outside of the market are the sole form of aid that should be used. This form of subsidy ensures that the financial resources are effectively directed where it is needed and do not distort competition or the integrity of the internal market. As investment aid lowers the risk of market distortions compared to operating aid and is easier to phase out, support schemes should be designed as a form of direct payment or tax relief. As stated in the EEAG support study published by the Directorate-General for Competition in 2021, grants had the highest effect on investment levels and investment aid did not score lower than operating aid regarding the effective securitization of investment. On the other hand, operating aid can have considerable distortive effects on energy markets and even work against the overall objective of a carbon neutral economy by 2050.

Q3. What power generation technologies should be subject to two-way contracts for difference or similar arrangements?

As stated in our answers to questions 1 and 2, we are critical of two-way state backed contracts for difference due to their distortive effects on electricity markets. Consequently, no power generation technologies should be subject to two-way state backed contracts for difference. Financial assistance for capital intensive non-mature technologies should always be provided via an investment aid and not a market distorting operating aid.

Q3.1 Why should those technologies be subject to two-way contracts for differences or similar arrangements?

See answers above

Q4. What technologies should be excluded and why?

As already stated in our response to question 1 we urge the Commission to take into consideration the potential detrimental effects of CfDs on the forward market and therefore refrain from the promotion of this subsidy scheme for all technologies, apart from RES if carefully designed.

Q5. 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?

i. Clear, long-term framework conditions provide protection against regulatory risks rather than state guaranteed CfDs.
ii. Careful consideration as to how the state guaranteed CfDs for offshore systems can be integrated into a future overall concept for the expansion of renewables and the funding system.
iii. Danger of a slippery slope away from market principles.
iv. State-guaranteed contracts for difference have a detrimental effect on the market and system integration, if volumes linked to these contracts are not placed on the market.
v. Sector integration is called into question.
vi. New, extensive funding programs worsen the market perspective for plants after the end of their funding period.
vii. Financing costs largely depend on competition, the learning curve and framework conditions.

As an alternative, market-based instruments – such as hedging instruments – can allow generators and consumers to limit a great part of their risk exposure.

Q6. What design principles could help mitigate the risks identified in question 4, in particular, in terms of procurement principles and pay out design? Should these principles depend on the technology procured?

As already stated in our response to question 1 we urge the Commission to take into consideration the potential detrimental effects of CfDs on the forward market and therefore refrain from promoting this subsidy scheme if not carefully designed so as to avoid detrimental effects on the forward markets, and tailored to specific contexts.

Q7. 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?

Please refer to the answers provided above.

Q8. What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type?

As already stated in our response to question 1 we urge the Commission to take into consideration the potential detrimental effects of CfDs on the forward market before considering a new legal framework for state-backed two-way CfDs.

Q9. 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?

EPEX SPOT is critical of CfDs, due to the reasons outlined in the answer to question 1. If nonetheless CfDs – or any other operational aid subsidy scheme like feed-in tariffs – are applied for a certain period, the generation assets should be integrated into the market after the clearly pre-defined expiry date of the scheme. This market integration is essential to continuously improve the marketing of power generated from renewable energy sources. This has the objective of ensuring that producers and consumers of power from renewable systems respond fully to the market price signal. In this context, the requirement is that income from marketing on the power markets is maximized while government funding/aid is minimised. The use of market mechanisms avoids misallocations, which would otherwise be caused because of the assumption of risks by the state.

Q10. Without prejudice to Article 6 of Directive (EU)2018/2001, should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity?

[NO]

No, we do not support in principle the application of CfDs on existing generation capacity. As stated before, regulatory uncertainty is one of the main barriers to investment in the EU.

Q12. How would you rate and address the following potential risks as regards the imposition of regulated CfDs on existing generation capacity?

(a) legitimate expectations/legal risks; *very high*

(b) ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts; *very high*

(c) locking in existing capacity at excessively high price levels determined by the current crisis situation; *very high*

(d) impact on the efficient short-term dispatch. *Very high*

(a) Any attempt to force CfDs on existing generation capacity will face legal risks, like questioning property rights.

(b) The defined strike price by the respective regulators/governments for CfDs is likely not reflecting a reasonable price level. An inefficient administrative setting of a CfD strike price will on the one side lead to significant economic losses for market participants investing in the energy transition. If set too low, it might tighten the availability of financial resources for the transition. If the strike price is too high, the state budgets will be put under pressure. Furthermore, it would introduce an unnecessary complexity when it comes to allocation, as strike prices do not only differ between sectors but also between projects.

(c) There is a risk of choosing a too high strike price for long-term CfDs. However, what is "too high" is difficult to determine when entering a CfD. The huge advantage of an exchange-registered long-term contract compared to a CfD is that each party can leave the contract (close the position at the current market price) in case its expectations or plans for the future change. This is not possible with a CfD.

(d) The negative impacts of forcing CfDs on existing generation assets for short-term dispatch are the same as the negative impacts of any (voluntary) CfDs. CfDs result in a "produce and forget" attitude, which is either impeding activity on short term markets at all, or at least impede the reasonable behaviour on short-term markets. If we want asset operators to be responsible for their short-term dispatch (and if we want them to take on balancing responsibility), short-term markets are the only reasonable way to organise short-term dispatch. If more volume is disregarding the signals sent by the short-term markets, grid operators will have to get more active in redispatch and system services - increasing costs for end consumers.

We suggest addressing these risks by not further extending CfDs beyond what's possible today.

Q13. Would it be enough for existing generation to be subject only to a simple revenue ceiling instead of a revenue guarantee?

[NO]

As already expressed in our answers above, we oppose imposing any measure on the existing generation. Consequently, the existing generation should neither be subject to a simple revenue ceiling, nor to a revenue guarantee.

Q14. What are the relative merits of PPAs, CfDs and forward hedging to mitigate exposure to short-term volatility for consumers, to support investment in new capacity and to allow customers to access electricity from renewable energy at a price reflecting long run cost?

CfDs, PPAs and forward hedging all have one thing in common: they are a tool to already now agree on a price to be paid in the future. In this sense, they can all mitigate price volatility and – if set at an appropriate level – support investment into new capacity. If the price is determined in a competitive process, it can be expected that it is set at or close to the *expected* long-run cost in all of the three contract forms.

However, there are important differences between the three contracts. One counterparty in a CfDs is the state and it can be questioned if the state is best placed to take part in price definition. Especially in case of forced CfDs, free and competitive price formation is not given.

This is different in PPAs: PPAs – because they usually are negotiated for an individual generator and a consumer – offer a lot of room for detailed, individually agreed rules, be it regarding start of production, minimum or maximum take-off, etc. PPAs to some extent also can lead to a "produce and forget" attitude on the generators side, but here this attitude is balanced with the guaranteed take-off of a concrete consumer. Thus, PPAs do not lead to inefficient dispatch behaviour, as opposed to CfDs.

Forward hedging, as opposed to PPAs and CfDs, does not mitigate the profile risk of intermittent renewables, but offers much more tradability due to the standard contracts' specifics.

So, while all three contract types can bring about reduction of price volatility, revenue certainty for investments and potentially prices reflecting long-term costs, they come with different weaknesses, which are especially pronounced in the case of CfDs.

- ### Subtopic: Accelerating the deployment of renewables

Q2. Do you see any other short-term measures to accelerate the deployment of renewables? If yes, please specify.

- **at national regulatory or administrative level, [YES]**
- **in the implementation of the current EU legislation, including by developing network codes and guidelines, [YES]**
- **via changes to the current electricity market design? [NO]**

a, b) The energy system must be fit for the expected increase in renewable production – decentralized and volatile. Congestion might increasingly become an issue for the EU energy network. Therefore, the development of local flexibility markets for market-based congestion management is a mandatory complement to the necessary but costly grid expansion. Such markets represent a ''soft'' and cost-efficient solution to complement grid development for tackling congestion through making best use of system flexibility increasing demand-side flexibility (see also question 3 below).
At EU level, to increase the deployment of flexibility solutions, the Network Code on Demand Response should be swiftly finalized.

At national level, Member States should fully implement the EU Clean Energy Package, which sets the pace for a renewed approach to congestion management, favouring market-based solutions as well as market-based flexibility procurement and prompting system operators to better coordinate their operations, all for the sake of a cost-efficient energy transition. As provided by the CEP, Member States should apply the Regulation (EU) 2019/943 Art. 13, providing congestion management has to be market-based, and transpose into national legislation the Directive (EU) 2019/944 Art. 32, providing DSOs need to consider alternative options to grid investments such as market-based flexibility procurement.

Primary focus should also be on boosting renewables through markets: the successful path towards full market integration of renewables shall be continued. Support schemes should be progressively phased out where not needed anymore, and replaced by all possible market remunerations, i.e., power exchange, GOs, PPAs, etc. This leads to more efficient market price formation and saves taxpayers' (electricity consumers') money. The EU Guarantees of Origin (GOs) market can potentially become the main EU-wide support mechanism.

(c) The existing electricity market design based on a marginal pricing, zonal model and portfolio-bidding is the best possible market design for incentivizing the deployment of renewables, as it ensures the cheapest generation capacities are always activated first. Within an energy future characterized by a high share of decentralized renewable energy, it would make no sense to centralize the EU power markets, developing a nodal market design with central dispatch. As data on renewable generation indicated, the existing electricity market design is fit-for-purpose for staying on track with EU Green Deal trajectory. Indeed, in 2022, wind and solar production scored a record of 22% in Europe electricity generation mix, passing gas generation for the first time (https://ember-climate.org/app/uploads/2023/01/Report-European-Electricity-Review-2023.pdf). Yet, more can be achieved: before making up new legislations to change the overall design of energy markets, it would be important to complete the EU power market integration, implementing what has already been agreed upon, i.e., the Clean Energy Package, through the following: achievement of 70% cross-border capacity made available and market-based TSO-DSO procurement of flexibility to optimize grid investments (see point a) and b)). Furthermore, EU spot power markets can be further integrated by (i) implementing the Nordic Flow Based Market Coupling, (ii) adding one Pan-European Intraday Auction only when recalculation of capacity is guaranteed, (iii) harmonising and shortening the time interval for which the market price is established and (iv) coupling the borders with the neighbouring countries of the EU. Finally, when it comes to the foundations of the Internal Energy Market, we strongly advocate against a fundamental change of both, the market design and the governance of market coupling.

Q3: 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?

The introduction of further renewables in the system risks creating local congestion at the Transmission and Distribution grid levels. We believe that the introduction of local flexibility markets will allow to lower the requirements to reinforce the network infrastructure or postpone it, with

1. a better allocation of flexibility resources,
2. the creation of price signals to foster the investment in flexibility resources and
3. a better coordination between TSOs and DSOs for the use of local flexibilities.

○ Subtopic: Limiting revenues of inframarginal generators

Q1. Do you consider that some form of revenue limitation of inframarginal generators should be maintained?

[NO]

Q2. How do you rate a possible prolongation of the inframarginal revenue cap according to the following criteria: [to be rated from 0-10, 0 being “not at all preferable” and 10 “definitely preferable”]

(a) the effectiveness of the measure in terms of mitigating electricity price impacts for consumers: 0

(b) its impact on decarbonisation: 0

(c) security of supply: 0

(d) investment signals: 0

(e) legitimate expectations/legal risks: 0

(f) fossil fuel consumption: 0

(g) cross border trade intra and extra EU: 0

(h) distortion of competition in the markets: 0

(i) implementation challenges: 0

We strongly believe the inframarginal revenue cap should not be prolonged after 30 June 2023, as agreed in the Council Regulation 2022/1854. We regret to see several Member States have implemented it, extending way beyond that deadline. Revenue caps on inframarginal technologies should not become a structural feature of the EU market design. If not well-devised, revenue caps can virtually become price caps, distorting the merit order, disrupting the price signal and endangering security of supply. It is fundamental that price signals are left intact, to strengthen investment incentives. In addition, the effectiveness of such instruments can be questioned, namely the revenue target expected by politicians might not be met. For example, the ‘’windfall profit’’ tax implemented in Spain in September 2021, has only raised €366 million until mid-2022, instead than the expected €9 billion (Eurelectric letter addressed to Commissioner Simson).
Finally, the unfolding of the revenue cap today in place across Europe has highlighted several drawbacks. During the last few months, each Member State has introduced complex cap mechanisms, which often differ from each other, fragmenting the Internal Energy Market into a complex patchwork of national schemes.

More in detail,

a) Its effectiveness depends on governments' ability to collect revenues and redistribute them to consumers. The mechanism itself does not mitigate the impact of price volatility for consumers
b) Such government interventions significantly reduce investors' certainty, endangering the EU decarbonization trajectory
c) If not well-designed, namely if the cap is set at a threshold that does not let certain generators to cover their short- and long-term costs, we risk those to withdraw capacity, endangering security of supply
d) See point b); moreover, the revenue cap might not fit with the reality of PPAs. For example, in Germany, it remains unclear whether existing or potentially new PPAs should be treated equally or differently. Overall, such uncertainty can decrease liquidity on long-term markets
e) The existing revenue cap has been legally challenged by several actors
f) Such government interventions endanger the EU Green Deal trajectory
g) The patchwork of national cap schemes across Europe can affect cross-border trade significantly, also with non-EU countries, which do not apply the same cap mechanism
h) As in point g), diverging caps distort the EU level playing field
i) Several months were necessary to implement the existing revenue cap by all Member States and many elements have been hardly sorted out (e.g., bodies responsible for necessary data collection and provision).

Q4. Should the modalities of such revenue limitation be open to Member States or be introduced in a uniform manner across the EU?

[EU]

Despite the drawbacks, if the EU decided to introduce such measure, it should be introduced in a uniform manner across the EU. Yet, a better alternative exists: a ''solidarity contribution'' tax for the whole electricity sector, such as the one agreed upon in the Council Regulation 2022/1854. This would resolve some of the drawbacks identified above: it would apply completely ex-post after market settlement, avoid complex implementation and destructive effects on electricity markets, refer to actual realized profits, and it could cover also realised gains on the retail level, besides the wholesale.

Q5. How can it be ensured that any revenues from such limitations on inframarginal revenues are channeled back to electricity consumers? Should a default approach apply, for example, should these revenues be allocated to consumers proportionally to their electricity consumption?

First, any form of government subsidy should only be targeted to vulnerable end-consumers, SMEs and industries. For non-vulnerable end-consumers, changes in price level should be seen as an efficient instrument for incentivize demand response.
Nevertheless, any subsidy scheme should still foresee demand reduction incentives, for example during peak hours. The goal of governments is to provide vulnerable end-consumers with direct monetary support, while encouraging demand reduction initiatives and preserving the correct

functioning of electricity markets. A mechanism that allocates revenues proportionally to previous year electricity consumption would leave out any incentives for demand reduction.

○ Subtopic: Alternatives to Gas to Keep the Electricity System in Balance

Q1. Do you consider the short-term markets are functioning well in terms of:

1. **accurately reflecting underlying supply/demand fundamentals** *[YES]*
2. **encompassing sufficiently liquidity**, *[YES]*
3. **ensuring a level playing field,** *[YES]*
4. **efficient dispatch of generation assets,** *[YES]*
5. **minimising costs for consumers**, *[YES]*
6. **efficiently allocating electricity cross-border?** *[YES]*

Q2. 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]

The wholesale electricity markets' price formation mechanism is based on marginal pricing, ensuring the cheapest generation capacities are always activated first, and so, demand is always met at the lowest possible cost. This mechanism gives investment signals in new clean technologies and allows power generators to cover their costs, eventually ensuring security of supply. Marginal pricing guarantees the best resources' allocation mechanism, in terms of their cost and efficiency: it activates the most economic and environmental efficient resources and delivers electricity where and when most needed, even across borders. Such mechanism creates dispatch signals that allow the deployment of most cost-efficient resources, such as renewables and flexibility assets. Further, marginal pricing has strengthened the solidarity principle among Member States, flowing energy where it is most needed. So far, alternative pricing models, which can provide a resources allocation, which is as much cost-efficient as marginal pricing, do not exist.

In addition, another proposal about market design configurations consists of substituting the European Day-Ahead auction following a pay-as-clear model based on marginal pricing with an alternative market set up – pay-as-bid, as implemented on the Intraday continuous market. If the pay-as-bid mechanism were applied in the day-ahead market, market participants would try to anticipate the market clearing price and bid above their marginal costs in order to maximize their profits. Hence, the power generation units' activation priority would be based on the traders' ability to best forecast the market price, instead of on their economic and environmental efficiency. Therefore, a shift from marginal pricing would generate negative consequences but not lower energy prices.

Q3. How can the EU emission trading system and carbon pricing incentivize the development of low carbon flexibility and storage?

By internalising the cost of carbon emissions, it will become more expensive for companies to emit greenhouse gases, making low-carbon flexibility and storage solutions more attractive. Encouraging demand response will also be aided by carbon pricing as the EU ETS provides a clear incentive for consumers to shift their demand to times when low-carbon generation is abundant and prices are lower, increasing the offer of flexibility and the demand for additional storage solutions.

Q4. 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)?

[YES]

The market participants should be allowed to trade as close to real time as possible to balance their needs.

However, the importance of trading close to real time for the integration of renewables must be nuanced. Indeed, with the improvement of weather forecasting in recent years, an accurate prediction of renewable outputs is usually available well in advance of the last hour. Many of the corrections in day-ahead forecast error for renewables generators are now carried out before the last hour and the forecast error accuracy gains are only incremental in the last hour. What is key for the facilitation of renewable integration is therefore innovation and the introduction of new products, rather than trading close to real time.

The importance of the last hour mainly depends on market design, market structure, country size, power generation mix, and even more so on the features of the European balancing markets. In addition, balancing requirements influence greatly the volumes of trade in the intraday market.

Most importantly, the possibility to trade closer to real time is subject to the ability of TSOs to manage a closer to real time allocation of cross-border capacity. Indeed, if no cross-border capacity is available, there is no justification for shifting the cross-border intraday gate closure time and pooling the liquidity closer to real time.

Q5. Do you consider that market operators should share their liquidity also for local markets that close after the cross-border intraday market?

[NO]

What would be the advantages and drawbacks?

On every market, effective and fair competition is the key principle. It is only in very exceptional cases that a regulatory framework may provide for the mandatory sharing of a facility or property. The sharing of liquidity between the cross-zonal intraday gate opening and gate closure times, as a clear interference in the market, was taken at the expense of competition between power exchanges, to facilitate cross-border trade.

However, preserving healthy competition between power exchanges and between other players contributes to accurate price on the spot market, innovation on exchange platforms and investment signals for new sources of energy, which are central for the cost-effective integration of renewable technologies in the electricity mix.

Besides, trading is also possible with other market places or Over the Counter (OTC) offering facilitation services. The further socialization of liquidity between NEMOs will create an unlevel playing field between NEMOs and other providers of trading options.

Moreover, there is no rationale for market operators to share their liquidity also for local markets in the absence of the provision of cross border capacity by the TSOs. When the liquidity is pooled in one order book, competition is limited to only a few of the parameters of competition and there is little room left for competition between power exchanges, whereas it is innovation and the introduction of new products that will be key to facilitate renewables integration. The German government also acknowledged in 2022 that it cannot be assumed that mandating the socialization of liquidity also for local markets would support competition development between power exchanges and that the negative impacts on product innovations and investments would not outweigh any alleged benefit (https://dserver.bundestag.de/btd/20/031/2003163.pdf).

Finally, it is unclear how the proposed measure relates to the declared goal of "*addressing the economic and social concerns related to high energy prices*".

Q6. 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]

What would be the advantages and drawbacks of such approach?

Mandatory participation in the day-ahead market could have negative effects for the spot market efficiency without having a downward effect on prices. In fact, prices are driven by underlying supply and demand fundamentals. In addition, mandatory participation does not belong to the EU Energy Market, based on fair competition among market participants and voluntary participation in the market.

For generation under PPAs, a mandatory participation in the day-ahead would need to be questioned as PPAs themselves are instruments made to minimize the short-term price variation. At the same time, generation under CfDs functions in a "produce and forget" manner, disregarding the actual situation in the grid. Thus, impacting prices and impeding the reasonable behaviour of short-term markets.

Q7. 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)?

We are not in favour of having further information in the bidding in the market that could decrease market efficiency and disrupt the price signal.

Locational: locational tags within the wholesale market would disrupt the price signal, reduce transparency and hamper the well-functioning of the wholesale market. Different markets should not be mixed up. Different markets are intraday, balancing and local flexibility with different products, uses, risks and so prices. In addition, locationally tagged bids would be technically not easy to implement.

Technology: portfolio-based bidding is the prerequisite for improving efficiency and liquidity of the spot market. Unit-based bidding is a less efficient model, for which market participants cannot deviate from schedules linked to individual transactions or are obliged to trade on the market every schedule variation. Instead, portfolio-based bidding allows the reallocation of production or demand within the same portfolio.
In addition, we believe unit-based bidding would not contribute to achieving one objective of this chapter, e.g., '*'improving the efficiency of intraday markets''.* Unit-based bidding is poorly flexible, highly complex and cumbersome, namely, unapt for the dynamic trading environment of intraday markets.

Q8. What further aspects of the market design could enhance the development of flexibility assets such as demand response and energy storage?

In terms of wholesale markets, demand response and storage can be further facilitated through more open access in terms of the overall market rules and arrangements. The Electricity Directive and the Electricity Regulation already set useful rules and frameworks for flexibility to develop. However, in some countries, the transposition processes and overall implementation are lagging behind.

In addition, to facilitate the progress of these flexible resources, the development of local flexibility markets can be a way to improve their profitability and their development, as well as help Transmission and Distribution System Operators handling congestions and improving their grid investment and grid operation costs.

Q9. 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]

From our experience, regulatory barriers in the system operator's incentive regulation act as barrier for the use of local flexibility, demand response, energy storage and other flexibility assets by system operators in their operations.

Traditionally, system operator's remuneration has been very dependent on CAPEX through accounting mechanisms based on their regulatory asset base, creating a situation in which there is a natural incentive for system operators to invest in the grid (CAPEX) to manage grid constraints, rather than to use other means such as flexibility (OPEX), which are not incentivized.

For this reason, we believe that existing incentive regulations based on CAPEX are fit to tackle neither the energy transition in an affordable way nor the development of flexible resources. A renewed incentive regulation approach based on TOTEX – where CAPEX and OPEX are on an equal footing – would be a very good way to improve the incentives around the grid-oriented use of flexibility resources and decrease the overall costs of grid investments and operations at EU level.

Q10. 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]

We consider that the use of sub-meter data can be beneficial. It could be considered in cases where sub-metering can help overcome identified barriers vis à vis main metering. As the share of intermittent and decentralised renewable power production grows, it is crucial – for operational security, ecological and economic reasons – that demand is made more flexible, especially at low voltage levels. In the Consumer-Centric Market Design (CCMD), active demand participation and flexibility foster innovative business models "behind the meter" to make the most of rapid electrification and digitalisation.

Q11. 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?

[NO]

First, it is crucial to keep separate two different concepts, demand response (DR) and demand reduction. On the one hand, demand response mitigates the occurrence of price spikes by delivering additional required capacity to electricity markets during peak times, and therefore, shifts demand in time to deal with short-term capacity constraints. Demand response does not necessarily reduce the overall demand, and hence, consumption. On the other hand, demand reduction consists of consumers reacting to already-manifested prices to reduce their energy consumption – e.g., by lowering heating in their houses or investing in energy efficiency measures, which can save energy over the long-term. Particularly during periods of crisis demand reduction is needed. At the same time, DR will be mostly needed if the supply/demand balance is tight at particular times – e.g., because of high peak demand for capacity during days of cold weather. If supply capacity is used at maximum, then price spikes are observed on the spot and balancing markets to signal the need for DR to shift the peak of capacity demand and relieve the constraint.

Finally, we convey that a new product as an ancillary service, or DR products, will not result in demand reduction, as the two concepts consist of two unrelated mechanisms, as above explained. Besides, before enabling such new products, we should focus on swiftly developing DR solutions.

Q12. 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]

We strongly believe the deployment of demand response (DR) should not be considered only during periods of crisis, but rather being a key, regular feature of energy markets. To foster demand response solutions, it could be beneficial to facilitate the integration of DR in the commercial short-term markets. In addition, default rules should be in place to sort all financial and physical settlements involved among the aggregator, the supplier, and at retail level between the concerned consumer and its supplier. In fact, a key issue with demand response remains the interaction between the demand response provider (i.e., aggregator) and the concerned consumer's supplier/Balance Responsible party. Such rules should take into account (1) the compensation of suppliers by DR aggregators and (2) the correction of the Balance Response perimeters, in the case the supplier and the aggregators are not managing to agree.

Q13. 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]

We remark once again Member States need to fully implement what has been already agreed upon, the Clean Energy Package, rather than completely overhauling the EU electricity market. The CEP already sets the pace for a renewed approach to congestion management, favouring market-based solutions as well as market-based flexibility procurement. Yet, its complete application is lagging behind across several Member States.

Indeed, the transposition of Directive (EU) 2019/944 Art. 32 into national legislations has been insufficient in recent years in a number of Member States. As the article mandates DSOs to consider alternative options to grid investments, such as market-based flexibility procurement, a push to further implement this directive would foster the development of local flexibility markets and will create the necessary price signals to incentivize the grid-oriented use of demand response, energy storage and other flexibility assets. This will help mitigate the overall cost of the energy transition for European end-consumers.

Q 14: Do you consider the current setup for capacity mechanisms adequate to respond to the investment needs as regards firm capacity, in particular to better support the uptake of storage and demand side response?

[NO]

We consider that in some EU countries, capacity mechanisms have the potential to become an important feature. To achieve this potential, these capacity mechanisms need to be well-designed so as to minimize the impact on market functioning and at the same complementing the energy-only market. Moreover, they should possibly be harmonized at EU level where needed. As such, capacity mechanisms can ensure timely investments in back-up and dispatchable generation and enhance security of supply to facilitate the integration of vast amounts of renewables in the next years. Also, such complement to the energy-only market could decrease the need for price spikes (to finance new investments) and the likelihood of price spikes occurring in the future. Yet, the current crisis would not have been alleviated by additional capacity markets, as its origin is rather due to shortage of energy supply (e.g., gas), not to lack of capacity.

Against the background of this potential increase in relevance, however, we believe that the basis for the current setup, Regulation (EU) 2019/943, needs to be further exploited. Finally, the current regulation needs to be adapted for allowing for a faster and easier approval of capacity mechanisms.

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

[NO]

There is a benefit in introducing locational elements in the current market design, but not to a long-term shift of European electricity markets to nodal markets with central dispatch.

Nodal is sound theoretically, but its implementation is based on the model developed in the 1980s and implemented in the 1990s and 2000s in some US states/markets. In terms of RES integration, US states have lagged significantly behind the EU. Europe's market model has proven its ability to generate large capacities of wind and solar. Moreover, the nodal design requires moving to central dispatch, which again has several major drawbacks to accompany the energy transition. For example, it remains technically impossible today to integrate and optimize, in one single algorithm, the entire European power system, the way market coupling is operating today. This becomes even more true with the integration of storage and all other decentralized assets. This already been a limitation in the horizontal expansion of RTOs in the US (large ISOs expanding across states) and the vertical expansion of markets at lower voltage levels (i.e., with DSOs).

Instead, developing local flexibility markets on the distribution level, incorporating coordination with the TSOs to manage the impact on the transmission network, can create an opportunity to promote DSR, prosumers and distributed connected generation without resorting to a full market redesign.
Local flexibility markets at the distribution level can complement grid development through tackling the challenge of grid congestions by making best use of system flexibilities. Flexibility markets centralise local flexibility offerings. They allow network operators to resolve physical congestions and flexibility providers benefit from an additional revenue opportunity without having to move towards a central dispatch system which is rigid, administrative/bureaucratic/monopolistic and characterised by inertia. Squeezing the entire system complexity that is driven by the decentralization into one single algorithm that handles the grid, asset and market complexity will not be fit for the Net zero future.

- ### Subtopic: Enhance the Integrity and Transparency of the Energy Market

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Q1. What improvements into the REMIT framework do you consider as most important to be addressed immediately?

Although the Regulation (EU) 1227/2011 as level 1 text has been in place for more than a decade, its wording proved to be flexible and apt to serve as a basis for the most relevant developments since its entry into force. We believe that there is only one major exception from this rule: in the meantime, new markets and products have been developed which do not qualify as wholesale energy markets and products in accordance with ACER.
For the short-term power markets, we believe the following markets /products should be covered by REMIT:

2. Balancing markets as they are closely correlated to other short-term markets and should be monitored and analysed together.
3. Guarantees of Origin and their respective markets to particularly focus on the value created by renewables.

Moreover, as far as flexibility and capacity markets are concerned, we see the need for further elaboration, clarification and standardization. Today, these instruments are not yet covered in a complete and consistent manner. For instance, the exact terms for reporting all necessary details require further detailing, data fields need to be created or adapted, markets need a concise definition, etc. This is needed to strengthen the trust in the flexibility instrument to introduce locational price signals on the one hand and to complement energy-only markets with a reliable and transparent feature on the other (i.e., for flexibility markets).

Finally, we encourage to review of the definition of “market participant” to include Distribution System Operators (DSOs). For instance, in physical power markets DSOs may sometimes hold inside information relevant for wholesale power markets but do currently not have an obligation to disclose it, as they are not always market participants under REMIT. For example, when a grid outage managed by a DSO limits the output from a generating facility, the DSO is the owner of the information but does not have an obligation to disclose it based on REMIT. There might be issues with similar types of entities in other wholesale energy markets. More generally, clear definitions of all actors and their exact responsibilities would enhance the overall quality of the REMIT framework.

Q2. 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?

First, although REMIT was designed as regulation, particularly the enforcement regime is subject to national legislation. We identify several fields of lacking harmonization in this regard:

1. We see the need for further clarification whether errors qualify as Inside Information to avoid divergent practices between the Member States. For example, for France, a decision of 2022 by CRE requires the publication of errors (subject to assessment on a case-by-case basis). In the Nordics, this is practiced by market participants (MPs). Thus, there is a risk of divergence between countries. Harmonization and clarity on the matter would be welcomed for the benefit of MPs. MPs need to know in which circumstances to publish. In addition, current publication focuses on producers while errors could be committed by other types of MPs. Those other types of MPs need to know whether they need to subscribe or not to the transparency platform. In addition, transparency platforms that focus on production information may have to adapt their offer to accommodate this new type of inside information.
2. The elements of the respective offenses/crimes and the sanctions differ considerably from member state to member state. For instance, according to Articles 2 and 3 REMIT as well as ACER's REMIT Guidance 6th edition, Chapter 6.2 (p.70), REMIT does not require intent ("[...], whether the behaviour is intentional or not is irrelevant to qualify it as a breach of Article 5 of REMIT in the form of 'market manipulation'"). Nevertheless, some NRAs consider intentional behaviour a necessary element of crime to constitute a breach or REMIT. In our view, REMIT should be applied in a harmonized way across the different EU jurisdictions.

Second, the cooperation between authorities and Persons Professionally Arranging Transactions (PPATs) needs to be improved and harmonized to assist PPATs in meeting their responsibilities for cooperation with authorities under Article 15 REMIT:

a) While we see a very fruitful cooperation with ACER, more detailed/harmonized information is needed from NRAs on sanction decisions so that MPs but also PPATs can learn from it. For instance, more aggregated/anonyms information on soft actions (formal warnings, control, on-site inspections, license suspension) taken by NRAs on market participants would strengthen REMIT enforcement.
b) More information on actions taken by authorities in relation to cases under review (e.g., power or gas market, which geographical area, which REMIT breach is suspected, whether closed with or without sanction) would facilitate the work of PPATs.
c) Agreement on thresholds or other minimum requirements to identify suspicious behaviours.

Third, ACER guidance notes need to be further developed. In general, ACER should continue producing practical case examples on the application of REMIT, but many of them require updates considering the swift development of markets and market conditions (e.g., algo-trading). Additionally, the examples presented could be improved to represent different power spot market conditions.

Forth, improved data and best practice sharing between energy, financial and competition authorities would be beneficial for the efficiency of REMIT and European energy market surveillance more generally. Putting in place a more formalised cooperation process for ACER and ESMA could improve data and intelligence sharing without creating additional burdens or implementation costs for market participants and other stakeholders.

Fifth, the definition of inside information and the definition of information relating to the unavailability of transmission/generation/consumption assets should be aligned. This would provide much needed certainty to market participants on what to report. This will also mitigate double reporting as, currently, market participants effectively report the same unavailability twice under different regulations.

Q3. 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?

It is difficult today to monitor the publication of insider information. If this remains a tricky and burdensome exercise, equal access to this kind of information is not guaranteed and insiders remain in a favourable position. We believe that the reporting of insider information could be handled consistently with transactions, i.e., through a limited number of reliable and monitored channels.

In addition, we see the need for further operational improvements; in most cases, it is not about regulatory but rather technical shortcomings. In this regard, we claim for the following improvements: (i) better data management and system performance to be ensured by ACER; (ii) shorter lead-time to tickets/questions/issues; (iii) higher level of coordination with other authorities; (iv) transparency to be given back to the market – it is the ultimate goal to increase the transparency and integrity of the market and to produce unproductive data silos at the authorities.

Another topic related to monitoring is the duties and responsibilities of organised marketplaces in the event of cross-NEMO transactions. Today, we are confronted with an increasing number of such cross-NEMO transactions in SIDC market, which means that the two different legs (buy/sell) of a single transaction are associated with different NEMOs. Consequently, PPATs such as EPEX SPOT only see one leg of the transaction. Therefore, they lack a complete picture of the transactions. We ask for ACER's further guidance clarifying the authorities' expectations of notification of suspicious cross-NEMO transactions from PPATs. In addition, the responsibility of regulatory bodies, which are the only ones having a full view of both transactions' legs, needs to be stressed.