– Consultation Response –

Europex response to the European Commission consultation on electricity market design

Brussels, 13 February 2023

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

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

In addition to traditional forward markets, financial PPAs represent an optional market-based management tool to hedge against price and volume risks in the electricity market especially for longer time horizons. However, there are indeed several factors that limit the conclusion of PPAs in the current environment:

a) Significant amounts of renewable energy sources in Europe are linked to state support schemes and therefore do not qualify for PPAs which has limited the growth of the PPA market and prevented it from becoming more mature.
b) Building new RES is being slowed down due to lengthy permitting processes, regulatory complexity and other factors, and therefore reduces the opportunity to enter into PPAs.
c) As a hedging tool PPAs are mostly only available to larger suppliers, industrial & commercial consumers with good credit risk profiles. They also come with significant legal costs as they are complex contracts and often require significant time and negotiation prior to conclusion.
d) The counterparty default risk needs to be insured in one way or another which comes at a significant cost.
e) In some markets, the pool of available participants may be limited, making it difficult for smaller participants in particular to conclude a PPA.
f) PPAs have a high-country risk for investors due to national taxation schemes or price caps.
g) Periods of high prices and high volatility render PPAs less attractive due to the related long-term risk and possible lock-in effects when electricity prices return to more typical levels.
h) There exist several additional practical barriers such as limited knowledge among developers and investors about the various market instruments available to them for hedging.

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?

No, there are better ways in which the use of PPAs can be encouraged than to revise the current electricity market design framework. First, regulatory certainty is of utmost importance, including by way of ensuring that no extra levies will be imposed (e.g. clawback mechanisms). Second, the grid infrastructure needs to be improved to be able to integrate new RES installations in the energy system and to ensure efficient price formation based on sufficient cross-zonal transmission capacity made available for trading.

Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity? If yes, under which conditions?

No, in order to better protect consumers, we would argue against an artificial large-scale PPA rollout that is not based on actual market demand. PPAs can be an effective tool for hedging. However, there should be freedom of choice regarding the market and contract type market participants would like to enter into.

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, there should be no stronger obligations on suppliers and/or large final customers, including industrial consumers, to hedge their portfolio using long-term contracts. Long-term hedging should be considered more broadly and according to individual hedging needs. PPAs are one specific tool among many options to manage risk and secure revenue streams for generators and investors.

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

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

how can these risks be mitigated?

a) This 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. A purely physical PPA with direct delivery indeed entails the risk of reducing liquidity in organised short-term markets as forward hedged physical PPA volumes may be traded OTC rather than on the organised day-ahead and intraday markets. (As regards virtual/financial PPAs, we do not see this risk.)

b) There is a risk that smaller power producers and smaller consumers might not be able to fund the collateral requirements for a long-term PPA. But small- and medium sized actors can currently gain sufficient access to financial PPAs via intermediaries. We see these conditions further improving with an additional up-take of financial PPAs. Moreover, standardisation will help small- and medium size actors to better understand and conclude PPAs. Increasing liquidity within the PPA market eases the process of market participants to find adequate counterparts and reduces the overall transaction costs.

c) This risk exists if non-market based PPAs are linked to national support schemes that are not harmonised.

d) We do not see this risk.

e) Under efficient framework conditions in a voluntary market there should be no increased costs for consumers. However, in case of an obligation on suppliers/large consumers to enter into a PPA for a certain share of their supply/demand, there is a risk that any increased costs associated with this obligation could be passed on to consumers in the form of higher electricity prices.

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. Forward hedging is a highly efficient way to mitigate exposure to short-term volatility and should remain the primary hedging instrument. We strongly support the role of forward markets in providing long-term predictability, protecting consumers from future price shocks and managing price and volume risks for market participants. Well-functioning forward markets are at the core of the Internal Energy Market which significantly benefits consumers at large. Against this background, we welcome targeted improvements to strengthen the core functions of electricity forward markets to protect consumers and ensure electricity markets can support the decarbonisation of the energy system.

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

Generally, EU electricity markets have seen a significant increase in liquidity in the past 20 years with the growth of organised trading platforms and the expansion of electronic trading. This has improved the availability and accessibility of forward hedging instruments and reduced their cost for market participants, ultimately benefitting the energy consumer. However, the level of liquidity varies significantly between bidding zones and regulatory barriers to further development persist. Also, the trend is not always upwards and the Nordic market, e.g., has seen a decrease in liquidity especially since the Nordic System Price is currently not functional as a single proxy for the 12 related bidding zones. This is due to the lack of transmission capacity and too small bidding zones with strong imbalances in supply and demand.

In some cases, it is possible for market participants in less liquid bidding zones to manage their risks through proxy hedging against more liquid markets. However, this is only possible if a good price correlation exists between the two markets. Additionally, given the specific characteristics of each bidding zone and the fact that physical markets differ significantly from financial markets, there is no one-size-fits-all approach to forward market liquidity.

It is important to note that in electricity markets in Europe there remains a high share of OTC bilateral transactions, often significantly outpacing the volumes of the orderbook trading of the more transparent organised trading venues.

While liquidity in forward markets has been temporarily affected by the recent geopolitical turmoil and the related supply shock, it is likely to return to a sufficient level when price fluctuations are driven again by market fundamentals instead of political uncertainty. Nevertheless, the framework conditions for trading in energy derivatives should be more flexible, and in particular allow for the use of a broader set of collateral (e.g. bank guarantees).

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

It is difficult to generalise the reasons why market participants face difficulties to enter into forward contracts. One aspect may indeed be the level of forward market liquidity which varies between different bidding zones. However, this liquidity challenge can be quite specific and complex for each bidding zone. In addition, national interventions can also constitute hindrances to entering into forward contracts as they may reduce the perceived need to do so. Subsidies on fossil, renewable and nuclear investments, for example, shield participants from market volatility and disincentivise forward hedging. We also see the same problem arise from regulated tariffs. Any potential supply subsidy must be carefully designed to encourage participation in forward markets for risk management rather than relying on government funds. From this perspective, there is indeed need for more harmonisation at EU level to avoid disadvantaging certain market participants. As far as collateralisation is required, for example, further expanding and harmonising the list of eligible collateral in financial regulation would improve the participants' access to forward markets. Cross margining among clearing banks could also ease collateral requirements and support liquidity.

Moreover, we see an important opportunity to educate market participants on the tools available to hedge risks as many are simply unaware of their options or unsure of how forward contracts work in practice. This is exacerbated by complex regulation and interventionist changes to energy and financial market regulation which can impact the participants' willingness to enter into forward contracts. Smaller participants in particular may also find it difficult to navigate counterparty and credit risks if they lack the resources to be able to adequately assess and manage these risks.

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 principle, market participants should be able to freely decide how they manage their risks. 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.

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

No, forward markets differ largely from physical short-term markets. The financial derivative market has no direct impact on physical flows. Its only purpose is to re-allocate risks and consequently organise future cash-flows. To provide adequate solutions to the further optimisation of the functioning of the forward market, it is crucial to analyse in detail the specificities hampering liquidity in the different bidding zones and consult the experiences of market participants.

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

Our overall assessment is positive. However, we acknowledge that the Nordic "regional proxy hedging" model faced some challenges over the past 10 years, which need to be duly assessed if this model was to be considered for application elsewhere.

Historically, the usage of a single Nordic 'hub' reference price, the Nordic System Price (NSP), was a very good model to do 'proxy trading' because it gathered most of the Nordic long-term liquidity in one reference contract that had good correlation with the vast majority of the Nordic bidding zone prices. However, from November 2011 onwards, when Sweden was split into four bidding zones, there have been 12 bidding zones in the Nordics, and the correlation and price convergence has gradually been reduced between the NSP and most of the Nordic bidding zones. One key reason for this is that the Nordic TSOs have not increased the cross-zonal transmission capacities to keep pace with the significant changes in the power supply and demand situation.

To have a perfect bidding zone hedge there is a need to complement trading in the NSP with trading in Electricity Price Area Differentials (EPAD) contracts which hedge the price difference between a given bidding zone and the NSP. However, several of the bidding zones are rather small and without a sufficient level of “natural” sellers and buyers that can supply long-term liquidity in that many EPADs. This has been further exacerbated by the growing spot price volatility and divergences in bidding zone prices. Also, liquidity has been further decreased by the introduction of new EMIR collateral rules in 2017 which ended the use of bank guarantees as collateral. However, and more importantly for “proxy hedging”, there is a need for European TSOs to support price convergence between bidding zones by investing in cross-zonal transmission capacity and refrain from setting up small sub-national bidding zones when it leads to the inability to secure sufficient forward hedging liquidity.

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?

Forward market development would significantly benefit from a streamlining of market rules and regulations, particularly financial services regulation. Simplifying these would reduce the barriers to entry for new participants and encourage the development of new products and services. Furthermore, refraining from policies which directly intervene in the market would improve certainty and help to promote forward market liquidity. Enhancing the predictability of market design allows participants to more confidently enter into long-term hedging positions and make use of existing products. Allowing for a broader variety of accepted collaterals by clearing houses could help market players to mitigate their risks via financial instruments. For example, the value of power or gas supply contracts follows the value changes of open positions, thus they could serve as good supplement to current solutions.

Measures to accelerate the permitting procedures for new renewable energy projects and increasing transmission capacity in power networks would also provide wide-ranging benefits for long- and short-term markets. In addition, the introduction of spread products with mandatory cross-margining among clearing banks as well as coupling could add liquidity for the forward market liquidity in some bidding zones. Finally, policymakers should carefully consider the effects of market harm (i.e., loss in liquidity) when deciding on bidding zone reconfiguration with smaller bidding zones usually leading to lower liquidity levels. Rather, ensuring that TSOs (and DSOs) invest in network capacity, adding supply flexibility, improving demand response, developing innovative storage solutions as well as limiting the scope and duration of subsidies can all contribute meaningfully to supporting forward market development.

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. Contracts for Difference (CfDs) can be concluded in a broad range of configurations. Aside from two-way CfDs as referenced in this question, many Member States already employ one-sided CfDs to varying degrees of success. Against this background, it is important to clarify the term “two-way CfD” to ensure all stakeholders are referring to the same concept. In our understanding, this subtopic refers to state backed CfDs whereby the state assumes the risk of investment. In this case, the state becomes the counterparty to all related transactions.

In case state backed two-way CfDs were to be implemented at scale, this would have a significant impact on long- and short-term market liquidity.

Depending on their specific design, CfDs are able to support investment stability thereby mitigating the exposure to wholesale price volatility, while ensuring a longer-term revenue stability, e.g. for new investments in low-carbon generation. At the same time, two-way CfDs keep a direct connection with the spot market to which they reference and may follow its volatility, again depending on their specific design.

While CfDs should not become the primary investment instrument for new renewable capacities, they could complement market-based tools in a target manner. CfDs can provide a stable income guarantee for new green technologies that may otherwise not become commercially viable. CfDs should be strictly limited in time and scope and only be used in such circumstances where market-based tools would not be feasible.

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. While CfDs should not become the primary investment instrument for new renewable capacities as they can distort price signals and negatively impact the well-functioning of spot and forward markets, they could complement market-based tools in a target manner. CfDs can provide a stable income guarantee for new green technologies that are not yet commercially viable. CfDs should be strictly limited in time and scope and only be used in such circumstances where market-based tools would not be feasible. As soon as such projects are commercially viable CfDs should not be entered into any longer. As recent experiences have shown, the roll-out of renewables is dependent on the right framework conditions. Therefore, the already identified bottlenecks, such as permitting and grid expansion, need to be addressed with priority.

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

If a particular technology is not yet mature enough to enter the market without support, there are less market distortive ways to subsidies this. For example, using upfront, one-time payments to get a particular technology off the ground would provide the necessary funding without the same negative effects CfDs would have on the market.

What technologies should be excluded and why?

All technologies.

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?

The scope and design of CfDs must be carefully considered to avoid subsidising technologies which are not climate friendly, for example if the support criteria were to refer to “inframarginal capacity” and the price of natural gas was to return to lower levels. Additionally, CfDs should not support technologies which can break even at market prices. Conversely, CfDs may lead to a situation where fossil fuel technologies are abandoned too quickly when they are still needed to ensure economic efficiency and security of supply – for example driving gas out of the market before there is an efficient alternative to handle the intermittent generation of renewables. There is also uncertainty as to how specific CfDs for offshore systems could be integrated into the needed future expansion of renewables and their overall funding framework.

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

CfDs for different technologies would require different time horizons as these technologies will gradually become more competitive.

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?

Generation should not be subject to a lifetime pay-out obligation as volumes would be withheld from the market.

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

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

We do not support the retroactive application of CfDs to existing generation capacity. Regulatory uncertainty is one of the main barriers to investment in the EU. If the basic underlying principles of the legislation keep on changing, the EU will be considered as an unreliable jurisdiction for investments, which will look for more stable alternatives elsewhere (e.g. in the United States).

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:** High
b) **ability of national regulators/governments to accurately define the level of the price levels envisaged in these contracts:** High
c) **locking in existing capacity at excessively high price levels determined by the current crisis situation:** High
d) **impact on the efficient short-term dispatch:** High

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?

Overall, it is important to make a large and diverse range of hedging instruments available for market participants to manage their long- and short-term risks according to their particular needs.

Forward markets are a means to hedge against price volatility in short term markets up to 3-5 years ahead with possibilities to hedge even up to 10 years. Forward hedging is the strongest tool at our disposal to mitigate price volatility and ensure renewable energy is efficiently integrated into the energy system. Forward markets allow consumers to secure a stable and predictable price for their energy supply by locking in a price in advance through the forward contract. They provide stability for energy producers by allowing them to secure a minimum price for their energy, even if market conditions change.

PPAs have several benefits. For consumers, PPAs provide fixed price contracts and a hedge against electricity price volatility. For investors in renewable capacity, PPAs provide a stable long-term income.

CfDs can also be useful for bringing new renewable technologies to the market.

RES volumes that have been hedged under RES support schemes and/or PPAs and are for physical delivery should be traded in the SDAC coupled day-ahead auction. This will set the right incentives for a closer integration of long- and short-term markets for renewables. RES support schemes and PPAs will have an incentive to align with standardised SDAC products to allow for seamless trading on the organised electricity spot markets. The volumes, in turn, will increase market liquidity, contributing to even more efficient and reliable price signals for market participants and investors in renewable assets. Participation of generation under RES support schemes and/or PPAs in the SDAC markets will also allow for a more efficient allocation of cross-zonal capacities, as no such capacities would need to be set aside for cross-zonal trading of CfD/PPA hedged RES volumes outside of the organised markets.

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

Yes. Guaranteed transmission grid access can ensure the connection of offshore wind farms and other offshore renewable energy sources to the mainland grid and hence the consumption centres. This can reduce project risks for investors, improve the financing conditions for new projects and provide a more predictable revenue stream for developers. However, there should be clear conditions and limits to this transmission access guarantee for offshore renewables which must explicitly exclude a prioritisation of offshore over onshore assets as this could impact price formation as well as system efficiency and lead to stranded assets if both sources were not treated equally in the legislation.

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

- **(a) at national regulatory or administrative level,** Yes
- **(b) in the implementation of the current EU legislation, including by developing network codes and guidelines,** Yes

In terms of EU legislation, the ongoing Renewable Energy Directive (RED) review should be finalised as soon as possible, and the new rules swiftly transposed into national law and comprehensively applied. When it comes to permitting procedures, Member States should swiftly identify 'renewable go-to-areas', ideally before the 30-month deadline set for national transposition. It is of utter importance that renewable permitting procedures are simplified, streamlined and accelerated to ensure the deployment of new renewable capacity stays on track with the 40% RES target proposed in the ongoing RED review.

Also, the energy system must be fit for such a massive increase in renewable production which will become inherently more decentralised and more volatile. Congestion might increasingly become an issue for the EU electricity grid. Therefore, the development of local flexibility markets for market-based congestion management is an essential 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 and increasing demand-side flexibility (see also our response to Question 3). At EU level, to increase the deployment of flexibility solutions, the Network Code on Demand Response should be swiftly finalised. At national level, Article 13 on redispatching of the Electricity Regulation ((EU) 2019/943) should be fully applied by all Member States to ensure that congestion management becomes market based.

(c) via changes to the current electricity market design? No

The existing electricity market design based on marginal pricing (uniform pricing) in a zonal model in combination with portfolio-bidding is the best possible market design for incentivising the deployment of renewables as it ensures the cheapest generation capacities are always activated first. As the future EU energy system will be characterised by a high share of decentralised renewable energy, it would make no sense to centralise the EU power markets by developing a nodal market design with central dispatch. In addition, before proposing further legislation for energy markets, it is critical to complete the EU power market integration by implementing what has already been agreed, i.e., the Clean Energy Package. The comprehensive implementation of measures therein, such as the 70% minimum target for cross-border capacity to be made available for trading and market-based TSO-DSO procurement of flexibility to optimise grid investments would already significantly help to incentivise further renewables uptake. Moreover, EU spot power markets can be further integrated by implementing the Nordic Flow Based Market Coupling and adding pan-European intraday auctions only when recalculation of capacity is guaranteed.

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?

Changes to regulatory instruments may be necessary to ensure that the necessary grid expansion occurs. This can include reforms that incentivise investment, ensure fair pricing and cost recovery, provide stable and predictable revenue streams and promote the deployment of new technologies and innovation.

The introduction of further renewables in the system will also create local congestion at the transmission and distribution grid levels. We believe that the introduction of local flexibility markets will optimise the use of network infrastructure through:

- Better allocation of flexibility resources;
- The creation of price signals to foster investment in flexibility resources;
- Better coordination between TSOs and DSOs for the use of local flexibilities which can alleviate or defer further infrastructure investment.

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

No

How do you rate a possible prolongation of the inframarginal revenue cap according to the following criteria: (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 believe the inframarginal revenue cap should not be prolonged after the date agreed upon in the related Council Regulation (i.e., by 30 June 2023). We reckon to see several Member States have already implemented national revenue caps which extend well beyond the jointly agreed deadline. Such revenue caps on inframarginal technologies must not become a structural feature of the EU electricity market design. They lead to multiple negative effects as the recent experience with the existing revenue caps show. Please see below our reactions to the points raised above:

(a) Their effectiveness depends on each Member State’s ability to collect revenues and redistribute them to consumers. The mechanism itself does not mitigate the impact of price volatility for consumers.
(b) These government interventions scare away investors, thereby endangering the EU decarbonisation targets.
(c) If not well-designed, namely if the cap is set at a too low threshold for certain generators to cover their short- and long-term costs, there is a severe risk that those would withdraw capacity from the market, putting at risk the security of supply and increasing price volatility with potentially extreme price spikes as a direct consequence.
(d) Similar to b
(e) The existing revenue cap has already been legally challenged by several actors.
(f)
(g)
(h) The agreed EU-wide revenue cap has been differently implemented across the 27 Member States, creating a patchwork of different national interventions across Europe rather than a unified response to the energy crisis. This is distorting fair competition in the markets and should remain a very temporary short-term intervention.
(i) Several months were necessary to implement the revenue cap in various Member States with some not implementing it at all, showing the complexity of implementation.

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

Despite the drawbacks, in case the EU decided to introduce such a measure, it should be introduced in a uniform manner across the EU. Importantly, a valid alternative exists: a ‘solidarity contribution’ tax, such as the one agreed upon in the Council Regulation, would collect revenues as late as possible in the process, not at the settlement of the exchange of the energy. On the contrary, the revenue cap distorts the merit order, and thereby the price formation mechanism. This would not occur through a solidarity contribution, applied ex-post. To minimise its negative impacts, such a tax should be applied uniformly at EU level, activated at clear market conditions (e.g. price spikes), for only a limited and pre-set time period.

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?

Collected revenues should be channelled back only to vulnerable end-consumers. In addition, an incentive for demand reduction should be included in such an aid scheme.

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

- **(a) accurately reflecting underlying supply/demand fundamentals:** Yes
- **(b) encompassing sufficiently liquidity**: Yes
- **(c) ensuring a level playing field**
- **(d) efficient dispatch of generation assets:** Yes
- **(e) minimising costs for consumers**: Yes
- **(f) efficiently allocating electricity cross-border:** Yes

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, there are no viable, efficient and trustworthy alternatives to marginal pricing (uniform pricing). It is important to remember that for more than two decades the European energy market design has been enabling free price formation, based on the equilibrium between supply and demand, including (when available) the utilisation of cross-zonal capacity in day ahead markets. Marginal pricing, together with European cross-border integration via market coupling, ensures cost minimisation for end-consumers by drawing first on the cheapest sources of electricity production. Furthermore, marginal pricing brings significant benefits to end-consumers by enabling transparency of the day-ahead price signal that is used in the long-term (forward) markets to help absorb short-term price spikes. In addition, marginal pricing improves the viability of existing and future investments into low-carbon technologies, added demand, demand response and storage without any further state-backed support, enabling the market-based recovery of investment costs.

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

By increasing 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. In addition, there will be a clear incentive for consumers to shift their demand to times when low-carbon generation is abundant and prices are lower, hence increasing the offer of flexibility and the demand for additional storage solutions.

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, market participants should be allowed to trade as close to real time as possible in order to be able to balance their needs.

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)?

There are examples of inefficient dispatch of generation because of a lack of locational signals, hence internal congestion is not identified.

Potentially there is merit in adding locational signals to the existing market design. Locational information can help to identify physical congestions which should be removed by TSOs. Otherwise, a bidding zone review would be triggered to ensure that bidding zones are more reflective of congestion constraints.

Importantly, any such consideration should be assessed against its possible impact on short-and long-term market liquidity and the likelihood that improved locational information would indeed lead to substantial structural improvements in overcoming the existing congestion.

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

Regarding 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 for more flexibility to develop. However, in some Member States, the implementation is lagging behind. Recent emergency legislation has also been unhelpful for incentivising further investment into storage and demand response. For example, capping prices removes a key investment signal, diminishing the overall interest of investors in these areas.

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 to help TSOs and DSOs to handle congestions and their grid investment and grid operation costs. With this in mind, it is important to note that TSOs/DSOs must not be tasked with operating flexibility markets as they are direct participants in this market.

Moreover, there should be a better integration of demand response in power markets. Dynamic pricing should be enabled as data management improves.

We would like to stress two specific aspects:

1) Production assets and flexible demand should utilise their flexibility and the market should consequently create incentives to develop dynamic tariffs for final consumers, including households. To ensure minimum protection for end consumers hybrid contracts like the ones proposed by the EC in its consultation paper would be welcome. It is equally important to ensure that retail consumers in particular are educated so that they can benefit from these contracts.

2) Locational flexibility is key to help the grid to alleviate local (e.g. DSO level) congestion. TSOs and DSOs should purchase local flexibility on the free markets on a commercial basis. It is also key to ensure that local flexibility markets are linked to wholesale markets.

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?

No. One can be agnostic as to whether the system operator's remuneration is mainly based on OPEX or CAPEX. Instead, the TOTEX should be taken into consideration to find the best overall solution.

Limitations in the system operator's incentive regulation constitute a significant barrier for the use of local flexibility, demand response, energy storage and other flexibility assets by system operators in their operations.

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

For this reason, we believe that existing incentive regulations based on CAPEX are not 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 when it makes senses and decrease the overall costs of grid investments and operations at EU level.

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. Demand response will, particularly in periods of crisis, be mostly needed if the supply-demand balance is tight and especially if supply capacity is used close to maximum and spikes are observed on the spot and balancing markets.

Before enabling a new demand response product as an ancillary service, the integration of demand response in the existing commercial short-term markets should be facilitated. The compensation of suppliers by the aggregators and the correction of the balance responsible perimeters need to be considered and default rules should be foreseen in case the supplier and the aggregator are unable to negotiate.

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

Yes. Regulation should consider default rules to take into account a) the compensation of suppliers by demand response aggregators and b) the correction of the balance responsible perimeters in case the supplier and the aggregator are unable to agree.

More generally, future emergency situations need to be anticipated and better reflected in the EU Electricity Regulation. Detailed requirements should be part of the network codes as well, such as the Network Code on Emergency and Restoration (NC ER).

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, there are several measures that could incentivise more demand side flexibility in the short- and mid-term, namely: a) financial incentives for flexibility assets (rebates and subsidies), b) improved data management and c) education and awareness-raising.

In this context, we would like to highlight that Member States need yet to fully implement the Clean Energy Package. The CEP already sets the pace for an improved approach to congestion management, favouring market-based solutions as well as market-based flexibility procurement. Still, its full implementation is lagging behind in several Member States which is why many of the positive effects cannot be observed yet.

This applies in particular to the transposition of Article 32 of the Electricity Directive ((EU) 2019/944) into national legislation which has been insufficient in several 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 these rules would foster the development of local flexibility markets and will create the necessary price signals to incentivise the grid-oriented use of demand response, energy storage and other flexibility assets. This will help to reduce the overall cost of the energy transition for European consumers and taxpayers.

We would like to stress two specific aspects:

1) Production assets and flexible demand should utilise their flexibility and the market should consequently create incentives to develop and enable dynamic tariffs for final consumers, including households. To ensure minimum protection for end consumers, hybrid contracts, like the ones proposed in the present consultation paper, would be welcome. It is equally important to ensure that retail consumers in particular are educated so that they can benefit from these contracts.

2) Locational flexibility is key to help the grid to alleviate local (e.g. DSO level) congestion. TSOs and DSOs should purchase local flexibility on the free markets, on a commercial basis. It is also key to ensure that local flexibility markets are linked to wholesale markets.

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. We believe that the current setup allowing each Member State to design its own capacity mechanism (subject to approval by the European Commission) seems to be oriented towards lending support to fossil-fuel based production assets rather than to incentivise the development of DSR and storage. CRMs should be permissible, however, ideally only as mechanisms of last resort which are only activated when strictly necessary and are eliminated once they are no longer required. This in turn would ensure that old power plants are mothballed while DSR and storage are being allowed to develop.

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

No

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

No. End consumers and the demand side more broadly can play a key role in the short- and long-term price formation both on wholesale and retail level by being exposed to spot prices. Regulated prices should be phased out in favour of variable contracts which allow consumers to switch suppliers and decide to alter their consumption habits depending on market conditions and their own needs. Supporting consumers to be active in reacting to spot prices helps the balancing of the system and can support forward (hedging) liquidity.

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

We believe the REMIT framework is a key tool to prevent and detect market abuse in European wholesale energy markets and adds significant value to the functioning of the Internal Energy Market overall. REMIT works well and has evolved significantly since its formal adoption in 2011. An extensive body of guidance has been developed and a complex and robust data collection and market surveillance system has been put in place which is overall fit for purpose. Against this background, Europex would like to insist that future improvements build constructively on this legacy and provide regulatory stability without further increasing the level of complexity. This should be ensured by a close dialogue between all involved stakeholders.

<u>Monitoring of transmission capacities</u>

One aspect that we believe needs urgent regulatory attention is reaching more clarity on the consistent and systematic monitoring of cross-zonal transmission capacity. Transmission capacities are paramount for price formation and even a minor capacity reduction in one Market Time Unit (MTU) can lead to a major price impact on the market. Withholding transmission capacity is explicitly mentioned in Recital (13) of REMIT and in subsequent ACER Guidance as a form of market manipulation. In practice, however, there is no clarity on which entity is responsible for monitoring if the transmission capacity provided in every MTU corresponds to the actual available capacity and is not unduly limited. This means that there likely exist breaches of REMIT in the provision of transmission capacities, e.g., through illegitimate capacity withholding, left undetected and with a significant impact on price formation.

Providing actual available transmission capacity should be explicitly covered in REMIT and the monitoring of it should be clarified. We find that the 70% minimum target for transmission capacity made available for cross-zonal trade is not an appropriate indicator and proactive monitoring is urgently required. Our experience from conducting day-to-day market surveillance shows this is a real problem which has a large market impact and requires urgent legislative and regulatory attention. To this end, a clear definition which explicitly includes the responsible entity for transmission capacity monitoring should be included in the REMIT review, not only limited to a recital but in the main body of the legal text. Further technical details could be clarified in the REMIT Implementing Regulation and additional ACER Guidance. In the short term, further harmonisation among NRAs could partly improve this issue within the existing legal framework. However, ultimately ACER is best positioned to monitor available cross-zonal transmission capacity at European level.

<u>Extension to additional products</u>

In principle, we support the current scope of REMIT “wholesale energy products”, which are defined as “electricity and natural gas”, as they represent the key grid-bound commodity markets in Europe.

As for a possible inclusion of other gases, like hydrogen, at this moment we believe that the market is not sufficiently mature yet to require such an inclusion. Nevertheless, for market actors to prepare for a possible future inclusion into REMIT, a reliable outlook and timeline would be welcome.

Finally, we do not support an extension to other non-grid bound commodities, such as emission allowances. Given that the latter are financial instruments under the Markets in Financial Instruments Directive (MiFID), they are already comprehensively covered by financial regulation, including the Market Abuse Regulation (MAR), among others, and their inclusion into REMIT would create an overlapping framework requiring a total revision of the system to accommodate duplicate obligations. In addition, the interdependence between gas and electricity on the one hand and EUAs on the other hand is limited and will be even more so with the scheduled expansion of the EU ETS to new sectors.

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?

Improved data and best practice sharing between energy, financial and competition regulators would be beneficial for the efficiency of REMIT and European energy market surveillance more generally. In this regard, we were pleased to see the creation of a Joint ACER-ESMA Task Force in October 2022 as this cooperation can improve data and intelligence sharing without creating duplicative reporting obligations for market participants and other stakeholders.

In addition, the relationship between ACER and the Energy Community should be clarified and upgraded and REMIT should become fully applicable to all Contracting Parties. We explicitly support central transaction, fundamental and inside information data collection and data monitoring by ACER as well as the coordination of cross-border investigations between EU Member States and Contracting Parties and directly between Contracting Parties. This is especially relevant as the Energy Community is moving ever closer to full market integration with the Internal Energy Market and the same market integrity and transparency standards should apply across the common market.

Fair competition between Inside Information Platforms (IIPs) should be ensured. Currently, ENTSO-E, ENTSOG as well as individual TSOs operate IIPs which are not in line with the principle of a competitive level playing field as they can socialise their cost of offering such as for inside information disclosure services. Hence, if those services are offered to market participants, including TSOs in the case of the ENTSO, explicit cost- reflecting fees including public price lists should be required. This would help to prevent further endanger the level playing field with the well-established inside information platforms set up by private companies.

Additionally, we believe that more transparency regarding REMIT enforcement decisions is needed. Publishing detailed case descriptions (also) in English will improve monitoring by Persons Professionally Arranging Transactions (PPATs) and compliance by market participants.

As also stated in our response to Q1, we find that clearly defining who is responsible for monitoring cross-zonal transmission constraints will improve enforcement. Transmission capacities are paramount for price formation and even a minor capacity reduction in one Market Time Unit (MTU) can lead to a major price impact on the market. Even though withholding transmission capacity is explicitly mentioned in Recital (13) of REMIT and in subsequent ACER Guidance as a form of market manipulation, in practice we have seen that there is no clarity on which entity is responsible for monitoring if the transmission capacity provided in every MTU corresponds to the actual available capacity and is not unduly limited. This means that there likely exist breaches of REMIT in the provision of cross-zonal transmission capacities, e.g., through illegitimate capacity withholding, left undetected and with a significant impact on price formation. In the short term, further harmonisation and cooperation among NRAs could improve this issue within the existing legal framework. However, ultimately ACER is best positioned to monitor cross-zonal transmission capacity at European level.

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?

All envisaged changes to REMIT should be considered from a cost-benefit perspective. Several elements that we believe should be improved within the existing REMIT framework include:

1. Review of REMIT definitions

On the Regulation level (Article 2):

a) Amendment of the definition of "market participant" to include Distribution System Operators (DSOs). In physical power markets DSOs sometimes hold relevant inside information but do currently not have an obligation to disclose them as DSOs are not automatically considered 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 although it is market relevant.

b) In general, clearer definitions of all actors and their responsibilities, would clearly be beneficial for data reporting and market surveillance. This includes, among others, specific definitions for beneficiaries, DMA providers and their clients as well as market participants trading financially settled REMIT wholesale energy products on third country venues. Overall, we strongly support the existing requirement that the ultimate responsibility for REMIT reporting remains with the Market Participants.

On the ACER Guidance level:

a) As demand side flexibility is one of the major instruments in achieving efficient price formation, the relevant market participants should be given guidance on how to remain REMIT compliant.
b) The definition of inside information in the sense of information relating to the unavailability of transmission/generation/consumption assets should be further specified in terms of thresholds. This would provide much needed certainty to market participants on what to report and avoids an unnecessary burden for smaller market players with insignificant small generation assets. The market size and the wholesale energy product concerned shall be decisive for the minimum threshold. An alignment with the thresholds of the Transparency Regulation should be considered.

2. Avoiding double reporting

In our experience, there is still significant work to be done to ensure that all NRAs have access to the data collected by ACER under the current provisions in Article 8. We support efforts to improve the use and quality of the existing ACER data. This includes the targeted addition of new fields to ensure specific data can be collected in an appropriate way. Two examples of the limitations of the current reportable fields are: (1) there is no means to separately identify the DMA client (where this is visible to the OMP) via a field other than the beneficiary field when that entity is not the reporting market participant (which is not per se 'the beneficiary'), and (2) there is no field to expressly flag that a transaction is an Exchange of Futures for Physicals (EFP) or an Exchange of Futures for Swaps (EFS). At the same time, a detailed cost-benefit analysis should be done regarding the number of fields which assesses whether fields are used effectively. For example, the approach to the population of field 34 (voice brokered) does not seem logical in our opinion.

Regular reporting of data from the electricity balancing market is an important next step in data collection. However, we believe that the process should be consecutive and first the surveillance at TSO level should be properly established, as is the case with other energy wholesale markets.

On 31 January 2022, ACER published its Decision No. 1/2022 requiring the reporting of additional information in relation to Single Intraday Coupling (SIDC) data. This decision provided the legal basis to identify all trading possibilities for market participants in the SIDC markets, including orders located in different bidding zones, depending on the available cross-border capacity. This decision was necessary because the information linked to these interconnections did not fit the REMIT framework for several reasons (i.e., no respective data fields, no explicit reference in legal documentation, no availability of data by market participants or OMPs, no legal personality of SIDC, no contractual relations to market participants as primarily obliged entities, risk of double reporting etc.).

We believe that this arrangement as provided by Decision No 1/2022 is sustainable and should not be replaced via a simple extension of REMIT, for instance by extending the definition of OMPs. Especially transaction data reporting under Article 8 REMIT does not fit for the reasons listed above.

Concerning data reporting and the calculation of the transaction record-based REMIT fee component, records that correspond to the resubmission of data (which is relevant for data quality) of already submitted records by RRMs or for which ACER has not implemented any validation rules or provided guidance in the Transaction Reporting User Manual (TRUM) should not be counted towards the fee calculation. Doing so would create additional costs for MPs and/or RRMs for the same reported business event.

About

Europex is a not-for-profit association of European energy exchanges with 32 members. It represents the interests of exchange-based wholesale electricity, gas and environmental markets, focuses on developments of the European regulatory framework for wholesale energy trading and provides a discussion platform at European level.

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