European Commission consultation on market design

A Eurelectric response paper

February 2023

Eurelectric represents the interests of the electricity industry in Europe. Our work covers all major issues affecting our sector. Our members represent the electricity industry in over 30 European countries.

We cover the entire industry from electricity generation and markets to distribution networks and customer issues. We also have affiliates active on several other continents and business associates from a wide variety of sectors with a direct interest in the electricity industry.

We stand for

The vision of the European power sector is to enable and sustain:

- A vibrant competitive European economy, reliably powered by clean, carbon-neutral energy
- A smart, energy efficient and truly sustainable society for all citizens of Europe

We are committed to lead a cost-effective energy transition by:

investing in clean power generation and transition-enabling solutions, to reduce emissions and actively pursue efforts to become carbon-neutral well before mid-century, taking into account different starting points and commercial availability of key transition technologies;

transforming the energy system to make it more responsive, resilient and efficient. This includes increased use of renewable energy, digitalisation, demand side response and reinforcement of grids so they can function as platforms and enablers for customers, cities and communities;

accelerating the energy transition in other economic sectors by offering competitive electricity as a transformation tool for transport, heating and industry;

embedding sustainability in all parts of our value chain and take measures to support the transformation of existing assets towards a zero carbon society;

innovating to discover the cutting-edge business models and develop the breakthrough technologies that are indispensable to allow our industry to lead this transition.

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Markets & Investments Committee
Customers & Retail Services Committee

Contact:
Charlotte RENAUD, Head of Markets & Customers - crenaud@eurelectric.org

Christian GRUBER, Officer – Wholesale Markets - cgruber@eurelectric.org

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Overview of Eurelectric's recommendations for targeted legislative changes as part of the reform

To improve forward liquidity

- **Easing collateral regulations in forward markets**, by widening the types of non-cash collateral under EMIR review, such as non-collateralised bank guarantees, or accepting underlying electricity production/ customer contracts/ ETS permits as collateral.
- **Facilitating cross-border hedging opportunities offered by TSOs through allocation of higher volume of Long-Term Transmission Rights with longer maturities (beyond 1 year)** and with more frequent auctions.
- **Considering voluntary mechanism for market makers in forward markets** to stimulate liquidity beyond the current timeframe - up to 7-10 years.

To promote long-term contracts and hedging mechanisms

- **Member States must address national barriers to enter into PPAs and other long-term contracts on a voluntary basis for both for large and small consumers.**
- **Providing dynamic guidelines for an ideal contract for difference (CfD) design & settlement, as there is a wide range of system needs and national specificities between Member States.**

Introducing legislation to set up a flexible resilience framework for suppliers at national level

- **Ensuring proper implementation of Art. 10 on information to be provided by suppliers.**
- **Introducing legislation allowing termination fees** (e.g. amending Article 12.3 from a derogation right of MS to an explicit right of suppliers when consumers voluntarily terminate fixed-price contracts).
- Introducing guidelines for a flexible resilience framework to be used by NRAs to perform regular stress tests and introduce reporting requirements for suppliers.

Improving the regulatory framework for capacity mechanisms

- **Developing guidelines to foster harmonisation of capacity mechanisms.**
- **Simplifying and automating the approval process and remove the temporary and last resort nature**
- **Developing harmonised capacity markets to support the development of flexible assets**

Restrict flexibility of Member States to undertake unilateral actions distorting market functioning

- **Ensuring proper implementation of Art. 3 of the Electricity Regulation** listing the principles for a sound operation of electricity markets.
- **Creating an EC guideline/framework or prohibiting certain types of intervention.**
- Removing "all obstacles" to the necessary and efficient growth, digitalisation, and automation of the grid infrastructure existing in national regulatory regimes.

Introduce a framework to coordinate future system needs

- Moving beyond the different plans that are foreseen in current legislation (TYNDP, ERAA) aiming at a global, whole-system system needs assessment, therefore encompassing not only adequacy and network (currently covered in 2 separate exercises) but also flexibility and considering cross-sector needs.

Executive summary

On the 13th of February 2023, Eurelectric responded to the European Commission Public Consultation on Electricity Market Design outlining its priorities for the forthcoming revision seeking to deliver a market in line with consumers' needs and that supports the decarbonisation of the electricity system.

We need an evolution, not a revolution

We are pleased to see that the EC consultation **does not fundamentally question the current electricity market design based on short-term marginal pricing and its key features** (cost-efficiency, cross-border exchanges, and competition between market players). In this regard, it is essential to stress that **the current market design is not the cause of high electricity prices, and the forthcoming revision must preserve the underlying features and benefits of the current Internal Energy Market.**

Having said that, we fully support the aim of the reform to accelerate investment into renewable energy sources (RES) and other low-carbon technologies, to **reduce our dependence on fossil fuels** and reach net-zero. This, all while **fostering customer engagement and ensuring the affordability of the energy transition** by bringing the benefit of RES and low-carbon generation more directly to all consumers.

The Electricity Market Design Reform is an occasion to reinforce the integration of the internal energy market. **Emergency measures should be developed on an ad-hoc basis to meet the specific needs of crisis situations and should always be targeted, temporary, and time-limited**. We therefore strongly caution against institutionalising exceptional interventions such as market revenue limitation, regulated prices or revenues.

Enhancing hedging opportunities and long-term contracting to enable needed investments while ensuring consumer affordability

The best way to ensure affordability and protect customers against high volatility in the short-term market is to provide an **enhanced customer contracting framework** enabling sufficient possibilities to hedge and contract (especially for the long-term).

Voluntary long-term contracts such as Power Purchase Agreements (PPAs), two-way contracts for difference (allocated through centralised auctions), as well as forward hedging, canplay a critical role to support investments needed for a decarbonised power sector. If well designed, these tools may present different but complementary hedging purposes to mitigate exposure to short-term volatility for consumers (depending on their wide range of needs and preferences).

Eurelectric recognises a **large imbalance in the development of PPAs across Member States**, due to different national circumstances. Against this backdrop, we suggest mandating Member States to remove barriers preventing generators and offtakers to engage in PPAs. In addition, PPAs can be supported by:

- **Introducing public guarantees or insurance mechanisms for counterparty risks in PPAs.**
- **Developing an impact assessment on the introduction of incentives for entities** (e.g. a supplier or a PPA aggregator) to supply services to cover the balancing/shaping risk through market mechanisms.
- **Supporting standardisation and transparency,** in particular through a pan-European voluntary platform to facilitate PPA trading, or voluntary standardised PPA contracts and products at EU level.
- **Stimulating demand in PPAs through public entities' sourcing and/or incentives for larger consumers.**

Conversely, **two-way CfDs** and similar arrangements have been effective tools to ensure a minimum revenue to producers while supporting investments in new capacity where investments are not forthcoming on a market basis. However, there are **several major considerations** we must address:

- **Participation in two-way CfDs or similar arrangements - for existing and additional capacities - must be voluntary.**
- **There is no 'one size fits all' CfD** – the detailed design of CfDs or similar arrangements is key to preserve price signals, efficient short-term dispatch and liquidity of forward market.
- **Mitigating the impact of short-term markets on final electricity prices should not be considered their primary objective** as their efficiency is highly dependent on the payback design and they can be detrimental for certain types of demand that do not require the hedging they provide.
- **CfDs should be allocated in general through a competitive process** in accordance with State Aid Guidelines, and when not appropriate or possible, other specific similar arrangements should be used.

Forward markets should offer efficient and effective hedging opportunities to market participants . However, as we have seen from the emergency measures introduced in 2021 and 2022, **market-distortive regulatory interventions can lead to significant liquidity reductions in forward markets.** Thus, regulatory stability should be ensured.

While forward markets are currently sufficient to mitigate part of the exposure to short-term volatility for a limited time horizon (1 or 2 years), they **do not provide enough long-term visibility to trigger investments.** To this regard, in order to improve the liquidity of forward markets in the current and longer-term horizons, Eurelectric recommends:

- **Easing collateral requirements**, e.g., by widening the types of non-cash collateral under EMIR review, such as non-collateralised bank guarantees, or accepting underlying electricity production/ customer contracts/ ETS permits.
- **Ensuring that TSOs facilitate cross-border forward hedging** through 1) allocation of a higher volume of long-term transmission rights (LTTRs) products with longer maturities (to match at least forward market product maturities), 2) more frequent auctions

3) keeping Financial Transmission Rights optionality, and 4) facilitating secondary trading for the exchange of LTTRs.

- **Considering voluntary mechanism for market makers** in forward markets to stimulate liquidity up to 7-10 years.

Current framework for capacity mechanisms must be improved to ensure long-term visibility

Finally, due to significant increases of low-cost variable generation in the future, **valuing flexible and firm capacity will be crucial to ensure adequate investments and guarantee system adequacy to the required level**. Well-designed, technology-neutral, and market-based capacity mechanisms will therefore play a key role in the future to complement the expected renewables build-up. Despite the need of capacity mechanisms across Europe, current legislation does not recognise this structural need and only allows them temporarily, as a last-resort solution andsubject to State aid clearance. This creates uncertainty on their stability and hence impact investors' confidence. **Therefore, the Electricity Market Design shouldconsider how to simplify and automate the approval process, and how to further foster their harmonisation along already defined key design principles**, while keeping sufficient flexibility to address national adequacy needs and specificities.

Striking the right balance between customer protection and supply offer regulation

We understand the objective of the Commission looking into solutions to ensure supplier viability so consumers can have reliable and affordable access to electricity. **However, prescribing what products suppliers must offer will not ensure prices and variety for consumers which meet their individual needs and match their risk appetite.** Rather than mandating suppliers to pursue specific hedging strategies tied to specific instruments or offer specific types of contracts, **we would recommend a principles-based, flexible resilience framework that should:**

- **Ensure strict implementation of Article 10 of the Electricity Directive** which requires suppliers to provide information to consumers on their rights and on proposed offers, including risks undertaken when signing a new contract.
- **Allow NRAs to conduct regular stress tests and establish reporting requirements** to ensure their resilience, either through hedging, financial robustness or other means. Such tests should be adapted to national specificities and take the suppliers' portfolio into account.
- **Align incentives for final customers and retailers by pairing any fixed price contracts with an adequate mitigation for contractual breach** (e.g., cost-reflective termination fees).
- **Ensure that barriers to long-term hedging and supply in forward markets are addressed** as key prerequisites.

Nevertheless, should obligations to offer fixed-price contracts be imposed on suppliers, these obligations should:

- Be paired with a right for suppliers to charge cost-reflective early termination fees.
- Remove supplier size discrimination to prevent competitive distortion (e.g. in Art. 11 of the Directive).
- Promote retail offers in parallel that include short-term incentives (e.g. offers like time-of-use tariffs, critical peak pricing, dynamic pricing, and dynamic rebates) for consumers with more elastic consumption.

Establishing a framework to identify and satisfy the evolving system needs to maintain security of supply

An enhanced framework for assessing, in a forward looking way, the evolution of system needs in terms of firm and flexible resources is necessary to provide visibility for market participants and network operators. The current indicative network and adequacy planning exercises will need to be broadened to include flexibility and cross-sector needs, for instance:

- **Extending the time horizon to a timeframe aligned with decarbonisation objectives,** reflecting the key policy targets and milestones of 2040 and 2050.
- **Improving and apply the Economic Viability Assessment to all system needs** - not only adequacy.
- **Stress testing the resilience of the energy system through an enhanced analysis of extreme events in the system needs assessment.**
- **Improve transparency on methodologies, assumptions and justifications** - for a better inclusion of stakeholders in the system needs assessment process.
- **Improve governance and stakeholder engagement -** even though some current developments, such as the organisation of stakeholder group meetings go in the right direction.

Using the Market Design to Enhance the Development of Flexibility Assets

We welcome that the European Commission is not only looking at solutions which protect consumers against unexpected electricity bill increases but is also investigating solutions that enable and incentivise them to contribute to the green transition through the development of flexibility assets and services.

Before considering additional measures, the European Commission should:

- **Ensure proper implementation by Member States of existing provisions in the Electricity Directive related to demand-side flexibility and aggregation** (Art. 13, 15, 17, and 32), including an accelerated roll-out of smart-meters to all customers to allow market participants to provide a wider variety of flexibility offers in which more final customers may participate.
- Address the further development of flexibility assets and services through ongoing relevant technical workstreams (EC Smart Grids Task Force & development of the new Network Code on Demand Response) instead of the market design reform
- Remove obstacles at national level **to invest in the necessary and efficient growth, digitalisation, and automation of the grids.**
- **Develop harmonised capacity markets as an instrument to support the development of flexible assets.**

Eurelectric response to the EC consultation on market design

1. Making Electricity Bills Independent of Short-Term Markets

1.1 Power purchase agreements

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/No*

X	Yes
	No

Q2. Please describe the barriers that currently prevent the conclusion of PPAs.

In some Member States different barriers remain to the development of PPAs:

- **Regulatory Risk**: PPAs require a stable regulatory framework to encourage investment and support long-term planning. The current crisis has created a precedent of interventions on inframarginal rents. Since the interventions started, the RES PPAs decreased from 8GW (y 2021) to 6.6GW (y 2022).
- **Offtakers' insufficient creditworthiness**: a major barrier across most sectors, particularly in heavy industry and manufacturing, and in less developed EU economies, where many have appropriate energy footprint for PPAs but are not rated by any major credit rating agency.
- **The issuance of longer tenors for Long Term Transmission Rights (LTTRs) is missing**. Today LTTRs are limited to a year ahead. We recommend allocating LTTR products with longer maturity to at least 3 years and beyond to allow cross-border PPAs.
- **Administrative or Regulatory barriers to PPAs**: the Electricity Regulation and the Renewable Energy Directive already address some barriers. However, these are not consistently implemented across the EU and some legal barriers persist. For instance, some countries have a limitation on the maximum duration of contracts with consumers, effectively preventing them from concluding a longer term PPA.
- **Technical nature of PPA contracts**: technical features and clauses of PPA contracts requiring bilateral negotiation may slow the entry into the market of less sophisticated offtakers (learning curve effect).
- **Difficulty finding offtake volumes beyond large corporates**
- **Shaping/balancing costs:** they need to be taken into account due to consumption profile and make RES PPAs more expensive, especially in some Member States with a lack of flexible resources and increasing variable RES penetration.
- **Lack of supply due to lengthy permitting procedures:** Eg 50% of the wind power plants in Norway were developed through PPAs. In 2019 the approval of new projects was paused, resumed only recently, affecting PPA supply.

Q3. Do you consider that the following measures would be effective in strengthening the roll-out of PPAs:

a) Pooling demand in order to give access to smaller final customers
b) Providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks)
c) Promoting State-supported schemes that can be combined with PPAs
d) Supporting the standardisation of contracts

e) Requiring suppliers to procure a predefined share of the consumers' energy through PPAs
f) Facilitating cross-border PPAs

Do you have additional comments?

Before going through how this tools may foster PPAs, we would highlight that each option must be carefully balanced in order not to draw liquidity away from short term markets.

a) **With a multibuyer PPAs via corporate consortia**, the consortium could sign PPAs on behalf of several buyers (not able individually to negotiate PPAs), jointly responsible for the contract.
b) Eg, (a)**Developing public guarantees or insurance mechanisms to large users when signing PPAs** (see ES, NO), for generators against offtaker default and for banks/lenders securing loan repayment; (b)**Extending them to smaller users**. To be done minimising competitive distortions. As the market matures further, it should be reviewed & phased out progressively.
c) Eg, in France, the RES bill now assessed would allow **project owners to access a publicly supported derisking scheme for part of their production and** producers might sign a PPA for the volumes not subject to public support. **This could allow producers to transition towards PPAs**. But new support schemes shouldn't be introduced solely for PPAs, rather tap into compatible schemes. Also, distinct participation criteria in PPAs and state aid must be in place to avoid arbitrage.
d) **The contracts standardisation (building on existing work like EFET PPA contract) would lower transaction costs across parties and enable secondary trading of contracts during their lifetime.** The latter would allow for easier resale if parties' circumstances changed. But it's crucial to realise PPAs are often used to solve a specific industry problem. Thus, freedom of contracting must be kept.
e) **The suppliers must have freedom of choice on how to hedge their procurements.** Imposing specific instruments would limit the competition in retail markets & increase costs.
f) We recommend allocating LTTR products with longer maturity to at least 3 years & beyond to allow cross-border PPAs.

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

X	Yes
	No

If yes, please explain which rules should be revised and the reasons.

- **A voluntary EU platform to match sellers & buyers:** first to facilitate supply & demand to meet more easily. It would provide standard PPA contractual arrangements, to facilitate secondary trading over the lifetime of such contracts if needed. This arrangement would also allow the platform operator to act as a central counterparty to PPA contracts, potentially backed by public guarantees. Its voluntary nature would still allow for bespoke contractual arrangements outside of the platform.
- **Stimulating demand & supply in the PPA market:** it could be considered to add incentives (but no obligations) for some categories of users to source a share of their

consumption through PPAs, like exemptions from RES levies in the electricity bill or public guarantees on PPAs. One example of such incentives could be a scheme for electro-intensive industry in Spain. If these customers agree to enter into longer term contracts for electricity supply from renewables (PPA with a government guaranteeing the credit risk), they enjoy a related discount on RES and cogeneration levy. Similar incentive apply and could apply in other Member States with regard to long-term contracts based on carbon-neutral electricity.

- **Remove the possibility to introduce in national regulations restrictions on the agents that are allowed to develop business models consisting of either pooling demand or supply of PPAs**. This would also include retailers sleeving (physical or financial) third-party PPAs to their customers.

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

	Yes
X	No

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?

	Yes
X	No

Q7. Do you consider that increasing the uptake of PPAs would entail risks as regards:

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

If yes, how can these risks be mitigated?
2000 character(s) maximum

We answered “no” under the assumption that the uptake of PPAs is achieved by removing barriers. If mandatory requirements are introduced on market participants to sell/buy PPAs then there will be serious negative side effects, including higher costs for consumers.

1.2 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
	No

We will not provide an answer to this question *as it contains two distinct objectives and we cannot respond with a common answer to those. Indeed, forward hedging can contribute to the first objective (e.g. to mitigate exposure to short- term volatility for consumers) is reached but for a limited time horizon, while forward hedging currently does not contribute to the second objective (e.g. to support investment in new capacity) is not due to the insufficient long-term visibility (e.g. beyond 2-3 years ahead) of forward market. We however support the development of the forward markets to provide hedging opportunities to mitigate market risk and reduce exposure to price volatility for both investment and market participants portfolios hedging purposes.*

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

	Yes
X	No

First, we consider that forward hedging is not an efficient way to support investments. It does not currently provide the long-term visibility needed by the CAPEX-intensive investments required for the energy transition or for system adequacy - e.g., firm reliable capacity. The lack of liquidity on longer time horizons (more than 2-3 years ahead, depending on the bidding zone) prevents such long-term visibility. The inadequacy of standard products with actual generation profiles (especially for peak load or variable renewables) may also leave the investor with a major unhedged volume risk. Furthermore, collateral requirements to enter forward contracts are also responsible for the lack of liquidity (see answer to the next question 7).

Forward hedging can however be sufficient to mitigate part of the exposure to short-term volatility for consumers but for a limited time horizon. The liquidity of forward market is insufficient in several bidding zones and the ongoing crisis has highlighted the need for a greater role in the market for long-term hedging instruments and contracts. In this sense, if properly designed, the development of the PPA/CfD mechanisms would help to bridge the current gap in the liquidity of forward markets for long durations – i.e., PPAs/CfDs as a complement / pull to the forward market.

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

The lack of interest on the demand side is due to relatively low and stable prices and uncertainties for suppliers on their long-term consumer portfolio (partly because some Member States introduced real or perceived ban on termination fees, providing disincentives for suppliers to offer fixed price contracts hedged on the forward market) lead to low demand for long-term hedging. As a result, forward power markets lack liquid products to hedge beyond 2-3 years – even in bidding zones with mature forward markets.

Regulatory interventions increase uncertainties which can affect forward market liquidity. They can potentially affect the market price and, hence, the value of the forward contracts (i.e. Iberian Mechanism, cap on intramarginal rents). Furthermore, specific regulatory frameworks may lower the need for hedging or even give an incentive to favor short-term markets.

Also, renewable generators under current support schemes may have no incentives to hedge in the forward market, especially when the support they receive is linked to day-ahead prices. The design of these schemes could however be adapted to provide some incentives for producers to hedge in forward markets.

Finally, the current volume allocated by TSOs for cross-border hedging in forward markets through long-term transmission rights is too low and limited to a year ahead, limiting long-term hedging strategies.

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

	Yes
X	No

We appreciate that the Commission is looking into best practices to preserve access to energy with reasonable prices for end consumers through strengthened retail markets. However, we **do not believe there is a one-size-fits-all approach when it comes to hedging strategies.** We would instead recommend a principles-based approach to assess suppliers' resilience, where regulators have the possibility to carry out regular assessments, like stress tests, which would form the basis of compliance. These assessments would aim to check the robustness of the hedging strategy taking into account the suppliers' portfolio without specifying the key features to be followed in their hedging strategies.

- We **do not welcome the imposition of hedging requirements**. Hedging of electricity suppliers should be in line with their customer portfolio, and as a result, will differ widely between suppliers. These differentiating factors are what allow suppliers to effectively compete. Even partial normalization of hedging strategies will undermine retail competition, lower the diversity of offers, reduce suppliers' ability to optimize their sourcing based on sound knowledge of their own portfolio and, in the end, be detrimental to consumers. Suppliers should also be free to choose how to hedge their short position with consumers (i.e. their portfolio of aggregated supply commitments with consumers), including by developing generation assets.
- Furthermore, when hedging requirements are in place and there isn't sufficient liquidity in the market, this puts suppliers at increased risk and increases the price for end consumers if the market is short (e.g., if implemented in the current circumstances, the forward market would be even shorter than it is now). Suppliers are not suitable market-makers and should be allowed to optimize their hedging strategies to avoid locking in high prices for consumers.

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

	Yes
X	No

If yes, do you consider that such virtual hub(s) should be developed at national, regional or EU level? / Do you have additional comments? 2000 characters

We have doubts on the fact that the creation of a virtual hub serving as new reference for the emission of Long-Term Transmission Rights (LTTRs) would significantly improve forward hedging. Indeed, even if the hub is liquid, the question of how to hedge the price differential between the liquid hub and each zone would remain as long as LTTRs in volume and in liquidity remain limited. Therefore, a **crucial pre-condition is to ensure the increase in liquidity of transmission rights.** TSOs are the natural counterparty for offering LTTRs. However, they don't necessarily have the incentives to engage in forward market. **Regulators should define requirements, in line with the transmission capacities, to ensure that enough LTTRs are offered.**

We consider that the overall impacts on the market design (price formation, transparency, efficiency of the market, complexity of the market) **of such virtual hub still need further exploration with quantified analysis** (not only based on qualitative assessments). The proof of added value in terms of efficiency needs to be shown through thorough impact assessment. Such work hasn't been done so far despite the insistence of market parties.

Nevertheless, we support further improvements in forward hedging (see recommendations related to facilitating LTTRs products and allocation in the next question) but we believe that they can already be implemented with the existing regulation.

Finally, we would like to recall that liquidity requires simplicity and that this option could introduce a high level of complexity that could lead to lower LTTRs issuance (or not usable) and jeopardise the attractiveness of forward markets.

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

	Yes
	No

We will not provide an answer to this question as we represent a European association.

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? ***3000 characters***

- **Ease collateral regulations in forward markets**, by widening the types of eligible non-cash collateral , such as non-collateralized bank guarantees, or accepting underlying electricity production/ customer contracts/ ETS permits as collateral. The recent EC proposal for EMIR review (Art. 46.1) will facilitate and encourage central clearing of derivatives by energy market participants and provide relief to the cash liquidity pressure.

- **Ensure regulatory stability:** regulatory uncertainty undermines investors' confidence in markets. In this regard, end revenue caps on existing inframarginal production.
- **Facilitate cross-border hedging opportunities for forward markets through improved long term transmission right products and allocation where LTTRs are used**. In particular:
  - **Increase long-term cross-border capacity volumes offered by TSOs** through more efficient capacity calculation and adequate investment where needed. Eurelectric continues to challenge the added value of Flow Based (FB) calculation and allocation which has not been sufficiently demonstrated and is hence not compliant with FCA guideline Art.10. Most importantly, it has not been proved that FB allocation will lead to more cross-zonal capacities being allocated, which should be the goal given the need for long-term hedging under current circumstances.
  - **Allocate LTTR products with longer maturitie**s to match at least forward market product maturities, a minima introducing 3-year tenor LTTR. Longer tenors could be envisaged to increase cross-border trading and enable cross-border PPAs (see our responses to questions 2 & 3 in PPA section above).
  - Investigate the possibility to **increase the frequency of auctions for LTTRs**. Details on the granularity of products and frequency of auctions should be carefully assessed and consulted with Market Participants.
  - **Keep the optionality of LTTRs** as they are used by Market Participants to properly hedge their underlying risks and exposures; and hence contribute to higher liquidity. Removing optionality will reduce buying/selling orders and be detrimental to the liquidity of the markets.
  - **Any change of allocation design must be carefully assessed through cost-benefit analysis and added value proven.**
  - **Facilitate secondary trading**, e.g. having power exchanges easing the exchange of LTTRs between market participants at a price agreed between them (commercial transaction)
- **Incentivising market makers** could also be considered to actively drive liquidity on these markets especially for horizons up to 10 years. These services should be contracted by a market-based process, **with voluntary participation.** The implementation practicalities should be carefully analysed; any mandatory scheme that would either impose a given market maker or constrain the market makers' remuneration would not be acceptable. Costs for consumers or other market participants must be duly considered before introducing such concept.

1.3 Contracts for Difference

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)?

X	Yes
	No

YES/NO - De-risking schemes such as two-way contracts for difference (CfDs) or similar arrangements have been effective tools to support investments in new capacity where investments are not forthcoming on a market basis. However, the rate of efficiency with *which they mitigate the impact of short-term market on final electricity prices is highly dependent on the payback design.*

There is an increasing demand for de-risking schemes to further stimulate investments across different technologies needed for a net zero power system. Voluntary CfDs or similar arrangements can be complementary to the development of market based PPAs, as these have been proven to be an effective support mechanism for investments needed for renewable and low-carbon generation assets that would not materialise on a market basis. Nevertheless, Eurelectric cautions against introducing any mandatory obligations for CfDs or similar arrangements, in particular on existing assets - like PPAs these must remain voluntary.

Depending on the system needs, national specificities, revenues and adequate payback design; CfDs can be a tool to provide:

- Greater exposure to consumers to the less volatile long-term costs of investing in renewable and low-carbon generation assets
- A reduction of renewable support or of non-contestable charges
- Additional means supporting investments in new capacity
- Subsidies for energy savings/grids/storage/flexibility …

Nevertheless, it is important to underline that we cannot rely on paybacks from CfDs as permanent source of revenue for a variety of objectives. The settlement mechanism allocates both costs and revenues (in the short-term the settlement will be a revenue for the system; in the medium to long-term the settlement will be a cost – as strike prices will be at below and then above market prices). Ultimately, badly designed two-way CfDs or similar arrangements can present several challenges - see answer to Q5 for further details.

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?

	Yes
X	No

YES/NO – If properly designed and implemented on a voluntary basis, two-way CfDs and similar arrangements may provide minimum revenue to producers. However, mitigating wholesale price spikes it shall not be considered the primary objective of publicly supported de-risking tool as it is not the most efficient and direct way toprovide price stability to consumers (e.g. require pay-backs). Mitigating wholesale price spikes impacting consumer prices should be pursued by promoting consumers' engagement through hedging instruments (either directly or through retailers) e.g. forwards.

Depending on the design of the pay-back scheme, revenues from well-designed two-way contracts CfDs (or similar arrangements) can be allocated to consumers. In this context, two-way CfDs may provide consumers with greater exposure to long-term investment costs of renewable and low-carbon generation assets. Thus, less exposure to volatile short-term prices.

When entered into on a voluntary basis, two-way CfDs or similar arrangements can be an effective subsidiary mechanism to attract new investments needed to decarbonise - provided these are governed by targeted criteria and do not stifle competition. However, there is no 'one-size fits all' CfD. CfDs should be designed in a way that maximises the system value of covered generation assets and must be adapted to the various renewable and low-carbon technologies.

In general, a market-based CfD for new renewable and low-carbon assets should be based on a competitive process - in line with EU State aid guidelines - to avoid overcompensation. In some cases, the use of competitive CfDs might not be appropriate and other specific similar arrangements should be used.

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

Given the adaptability of two-way contracts for differences and similar arrangements, all renewable and low-carbon technologies should be eligible on a voluntary basis.

Two-way CfDs or similar arrangements should be used as a voluntary and market-based mean to realise investments in renewable and low-carbon solutions. CfDs should be used where incentives are not enough in the regular energy or capacity market (e.g., firm and flexible capacity). Therefore, CfD contracts should be adapted to the various renewable and low-carbon technologies as there is no 'one-size fits all' CfD. Irrespective of the technology, any generation capacity – i.e. existing and new built - should not be subject to mandatory two-way CfDs or similar arrangements.

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

To achieve the trajectories set by National Energy and Climate Plans, Member States might need to provide dedicated de-risking schemes in the form of two-way contracts for differences or similar arrangements for some categories of new assets, in addition to investments delivered by other market-based instruments -like PPAs and forward markets. Taking into account that there is no "one-size fits all" CfD, **the allocation process should foster cost reduction and innovation. Hence it requires competitive tenders** ("competition for the market").

Q4. What technologies should be excluded and why?

Eurelectric acknowledges the prerogative of Member States to determine a suitable mix of technologies needed to comply with the objective of climate neutrality and a net zero power system. To this regard, two-way CfDs or similar arrangements must ensure technology neutrality.

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?

A large use of two-way CfDs or similar arrangements may lead to a strong decrease of liquidity in the forward markets that could be detrimental to all actors.
For instance, if two-way CfDs with day-ahead reference price were to become the main mechanism to develop capacities, generators would no longer need to hedge on the

forward curve. Suppliers could hence have difficulties to find counterparties buying power on the forward curve and offering fixed price contracts to their customers.

If designed inadequately, two-way CfDs or similar arrangements can present several challenges risking of offsetting advantages - for instance:

1. Distorting short-term price signals
2. Negatively impacting short-term dispatch optimality
3. Negatively impacting hedging policies of retailers
4. Negatively affecting demand that does not want a hedge - such as electroliers, heat-pumps, demand side response, etc.
5. Hindering market functioning – e.g., reducing liquidity in forward markets

Thus, participation in two-way CfDs or similar arrangements for existing and additional capacities should be voluntary and market-based. Additionally, two-way CfDs or similar arrangements should be accompanied by additional safeguards and tools ensuring that new CfD-supported generation capacity is available on the forward markets while levelling the playing for PPAs (state guarantee, support from the demand-side, etc.). .

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?

The following considerations must be taken into account when designing two-way CfDs or similar arrangements:

- **Investors prefer a well-regulated counterparty for CfD allocation** with a clear mandate outside any political process (see for instance the Low Carbon Contracts Company in the UK).
- **Reference prices should not be based on a single market product**, but on a set of products, including forward prices.
- Guarantees of Origin associated with the generation should be allocated to and owned by the producers who are taking the industrial risk.
- In case of negative prices and in line with State Aid provisions, CfD features should ensure that support is not granted during their occurrence.
- In general, the design of the CfD should preserve the incentives for efficient dispatch and active hedging of the position.
- Clarity is needed on the treatment of congestion risks (esp. for offshore wind projects). The risks associated with grid development should not be borne by the investors/operators.
- One important point to consider is the treatment of cross-border exchanges for CfD settlement. A methodology to allocate the settlements should be defined at EU level to ensure a level playing field (with regard to the fact that certain Member States have important generation capacities located on their territory whereas others largely import renewable power generated in other Member States, thereby contributing indirectly to the revenues of those generators). It is already the case for allocation of several existing support schemes across the EU.

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?

Provided that CfD offtakers must offer their long position to end-consumers and retailers with transparency in a non-discriminatory way (e.g., through secondary auctions and a wide range of different contract durations), **revenues and costs from two-way CfDs and similar arrangements shall stay in the energy system and be reinvested where mostly needed.**

For instance, to reduce system costs and customers' bills, pay-outs could be reinvested to:

Introduce a specific levy (positive or negative) on the end consumer bill to pay the support or return the differences between the strike prices of public counterparty CfDs and wholesale market reference prices

Additionally, **a mechanism to protect consumers** from exceptional risks must be defined, either based on targeted measures (like "energy vouchers") or a structural shield. The financing could integrate a contribution from the public budget or the pay-back revenues from public two-sided production CfDs in case of high electricity prices. The choice could depend on the preference of the Member States and be subject to State aid approval if deemed relevant.

It is however important to underline that we cannot rely on paybacks from CfDs as permanent source of revenue for a variety of objectives. In the short term, CfD strike prices will be below market prices and the settlement will be a revenue for the system. However, in the mid/long term there will be many cases where CfD strike prices will be set above market prices, and thus the settlement will be a cost. The settlement mechanism needs to take into account that there is a need to allocate both costs and revenues.

Q8. What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type? *2000 characters*

As there is no 'one-size fits all' CfD, two-way CfDs and similar arrangements should have an adequate duration to provide visibility for investors and cost benefits for consumers.

Ideally, the duration should correlate with the investment's payback period, and be proportionate to the economic lifespan of the underlying assets to limit the risk allocation for public counterparties (i.e., for consumers ultimately). Consequently, contract duration can vary, depending on the technology characteristics and the trade-off between market risk for renewable and low-carbon generation. Longer contracts are needed for larger investments that need to be financed over a longer period. Whereas medium term contracts would allow repowering, refurbishing and upgrading new generation assets throughout the course of their lifetime.

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?

Two-way CfDs and similar arrangements should be used as a tool to enable the investment and alleviate risk, not to cap income.

When setting the CfD' strike price in a competitive allocation of CfDs, expected revenues after the expiration must be factored in. **After the expiration of two-way CfDs and similar arrangements, generation should be free to earn full market revenues and should not be bound anymore to the pay-out obligation of the CfD contract.**
Allowing to earn full market revenues after the CfD expires means removing risks associated with two-way CfDs and similar arrangements affecting system efficiency and market integration (e.g., muting signal for demand-side flexibility; impact forwards market liquidity etc..). In case a lifetime pay-out would be considered desirable, the support side of the CfD should be granted over the lifetime of the asset.

Q10. Without prejudice to Article 6 of Directive (EU)2018/2001[1], should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity? If such possible use of regulated CfDs for existing generation is deemed appropriate, should the obligation apply to all types of existing inframarginal generation or be limited to certain types of generation (and if so, which types)?

	Yes
X	No

Eurelectric is fundamentally opposed to the principle of imposing two-way CfDs or similar arrangements by regulatory means on existing generation capacity, regardless of their technology.

Investments in existing generation were made under the assumptions of market revenues. Imposing two-way CfDs or similar arrangements by regulatory means on existing generation capacity would have a **significant distortive effect** on the price setting for customers and would greatly **reduce competition in retail**. Furthermore, and more importantly, r**etroactive measures undermine the investors certainty** needed for capital-intensive investments for decarbonisation.

Existing generation must be allowed to compete freely to keep liquidity in short-term markets and to establish a reference market for two-way CfDs or similar arrangements (the latter are not a price maker but rather a price taker). Thus, existing generation capacities should remain free to enter private long-term contracts such as PPA or to sell their production on the forward market.

[1]
Article 6 (1): Without prejudice to adaptations necessary to comply with Articles 107 and 108 TFEU, Member States shall ensure that the level of, and the conditions attached to, the support granted to renewable energy projects are not revised in a way that negatively affects the rights conferred thereunder and undermines the economic viability of projects that already benefit from support.
Article 6(2): Member States may adjust the level of support in accordance with objective criteria, provided that such criteria are established in the original design of the support scheme.

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

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

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

	Yes
X	No

In line with the previous answer, **Eurelectric opposes imposing any measures on existing generation capacities.**

The revision shall acknowledge that **managing a portfolio including a generation fleet has its costs and extra revenues are used for recovering investment costs, innovation and further development**. A simple revenue ceiling puts a disproportionate risk on existing generation owners. In the years before the current energy price crisis many generation assets in Europe failed to recover their investment costs.

Additionally, retroactive change in regulatory rules and business environment would **breach operators' and investors' confidence.**

Revenue ceiling outside of Europe (see for example the Australian revenue ceiling that has been tested during 2022 and that has contributed to the capacity shortfall leading to the newly proposed capacity investment scheme with an agreed revenue floor) have very well illustrated their perverse effects in terms of market functioning and of security of supply. They exemplified why revenue ceilings are simply a bad idea and why they should not be considered.

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?

Forward hedging, PPAs, and CfDs, all have a role to play when it comes to mitigating exposure to short-term volatility for consumers. If well designed, these instruments present **different but complementary hedging purposes** that need to be adapted to a wide range of needs and preferences of customers.

Addressing barriers to enter PPAs must be a priority in particularly Member States as these prevent the mobilisation of private capital needed for a net zero power system.

However, PPAs do not necessarily suit the needs and preferences of every energy customer and can be c**omplemented by CfD auctions** - which reduce the cost of capital for developers and enable the achievement of renewable and decarbonisation targets. Despite PPAs currently mostly serve industrial consumers extending the possibility to engage in similar market-based long-term contracts to other consumer segments, may help decreasing customers invoice by shifting the need for public support and keeping stable prices for longer period.

Two-way CfDs and similar arrangements are an effective tool to enable investments in renewable and low-carbon technologies through competitive tenders, if voluntary sand market-based. Additionally, keeping revenues and costs of two-way CfDs and similar arrangements within the energy system may provide financing means for future investments needed for decarbonisation while ensuring a minimum revenue to producers .

Forward hedging could shield consumers from unwanted short-term price volatility impacting affordability. In practice, it helps cushion the impact of price shocks but it does not remove them. For instance, it could be crucial for existence of fixed-price contracts over a limited horizon (below liquidity of forward markets).
All three instruments should be used according to their relative benefits as described above.

1.4 Accelerating the deployment of renewables

Q1. Do you consider that a transmission access guarantee could be appropriate to support offshore renewables? ***Yes/No***

x	Yes
	No

If yes, Do you have additional comments? 2000 characters
If No, Please explain and outline possible alternatives. 2000 characters

Yes, should Offshore Bidding Zone (OBZ) be implemented, we are supportive of the TAG solution. It should however be supplemented with a share of the actual or expected congestion rent to the offshore wind developer (see explanations below) to facilitate investment in hybrid offshore projects. However, the decision between the OBZ and Home Market model should be decided at Member states level. In some cases, a better solution would be to stick to the Home Market solution.

First, it is necessary to specify that the Transmission Access Guarantee (TAG) solution comes with the decision of an Offshore Bidding Zone (OBZ) model (versus Home Market model). To our best knowledge the choice for this model has not been acted so far. We do not have within Eurelectric a unanimous preference between these 2 models as Member States are not concerned in the same way by these hybrid offshore projects (I.e. offshore renewables that are connected to more than one bidding zone). To properly plan and dimension the network, exactly as if it was produced in an onshore facility, we believe that it is better to follow a case-by-case approach for specific offshore windfarms and interconnectors. Thus, we consider that the choice of this OBZ model should be decided between the countries connected to such OBZ and must be done in full transparency.

Then, in case an OBZ is implemented, we believe that there is a need to design a coordinated support mechanism between the countries involved to address volume/price risks that generators would carry to facilitate decisions of investments. We recommend standard mechanisms that would be based on the allocation of a share of congestion rents to offshore developers to compensate the volume risk as of the TAG option but also the price risk. The TAG formula should be adjusted from Engie Impacts suggestion to: Max(reference bidding zone price – OBZ price, 0) x total offshore generation available to the market <u>+ spot price in OBZ x total offshore generation prospectively curtailed</u>. The trigger for the TAG should also be adjusted so that it only triggers when the capacity allocation is affecting the offshore generators. This support mechanism could be applied subject to minimum dimensioning of the interconnection capacity, to be defined. In this way, TSOs are kept incentivized to offer as much interconnected capacity as possible. Having say that, it is necessary to make sure that TSOs compensation is fair in order to not be to the detriment of the development of other low carbon technologies that also need to be developed rapidly to reach the targets; and not be too costly for the consumer.

Q2. Do you see any other short-term measures to accelerate the deployment of renewables?

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

If yes, please specify
2000 character(s) maximum

- **Ensuring a proper implementation of the Electricity Regulation and transposition of the Electricity Directive** at national level.
- **Ensuring that any change related to requirements for grid connection should rather take place in the framework of the grid connection network codes** – which are currently under revision - and not in the revision of the EMD.
- **Enabling DSOs' role to sign up market-based contract with flexibility service providers.**
- When facing congestion, **enabling SOs to choose the most cost-efficient solution or combinations of options of the different tools** at its hands (e.g.**congestion management, grid investments, non-firm connection agreement etc.)**
- Ensuring that **MS do not set taxes that disincentivize the build out of more renewable energies.**
- **Accelerating RES Permitting processes and related grid** through a reduction in the time spent on project examination and litigation. The recognition of the superior public interest of renewables could contribute to this acceleration. The spatial planning of the development of renewables must not be an additional barrier to the development of projects. Anticipating the development of networks is also a factor of acceleration.
- **Securing access to raw materials:** raw materials shortage is set to become a major hurdle for RES deployment.

- **Easing the so-called "endogenous rationing"** in par. 103 of the CEEAG, as it has led to a downward spiral of the tender volume and, consequently, to less Renewable projects being built. In many MS, the reason for undersubscribed RES bidding is mainly related to problems with slow permitting and/or increasing of prices/unavailability of raw material.
- **Rolling out voluntary granular labels:** Enable voluntary granular green certificates, in order to allow for development of 24/7 CFE policies that incentivise storage and flexibility under a voluntary arrangement between the parties.

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?

There is a major interdependency between the necessary built-out of RES and the necessity to accommodate that built-out also in the grid on both transmission and distribution level. In other words, **if policy accelerates renewables, there is a need to accelerate the grid by supporting its expansion, flexibilisation and further digitalisation with more anticipatory and non-regret investments**. According to our study "Distribution grid investment to power the energy transition" around **400 billion € of investments are needed to make the network fit for the energy transition**. It is therefore essential for system operators to forecast grid investment in an efficient way.

In this respect, we are convinced that t**he regulatory framework at national level, with appropriate returns on investment, is still best suited to solve the issue**.

In some cases, we are convinced that adjusting national approaches will be beneficial. Thus, **we would advocate to complement the existing EU electricity directive in a way that gives a clear signal to the Member States that grids must grow and be digitised significantly and "all obstacles to the necessary and efficient growth of the infrastructure that might be existing in the national regulatory regimes today, must be abolished**". An example of "obstacle" is the current investment cap set in Spain since 2013 which was imposed as a reaction to the financial crisis. The limit is no longer necessary nor justified, but the Spanish Government has not removed it yet.

Finally, most regulatory systems today will only recognize investments that are being used i.e., the DSO are usually only building grids after a demand has been realized. This leads to a situation in which DSO grid investments must "tail" the demand.

But the EU Package " Fit for 55' and 'RePowerEU 'plan give clear targets and enough certainty in terms of the electrification necessary to make the transition happen (e.g. "Go to area" which provides enough certainty for RES built out and thus the related grid investment), it is therefore advisable to at least open national regulatory frameworks and permitting procedures for DSO to also be building grid on forecast based on those forward looking objectives and incentives. Such plans could be the network development plans that DSO must deliver every two years according to article 32(4) of the Electricity Directive.

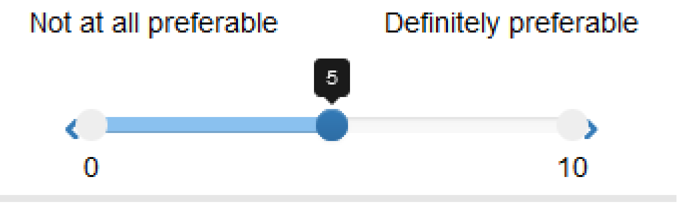
Preparing the electricity grid ahead of time and need to be able to cope with the increasing oad and quality demanded by an ever more electrified economy will ensure a successful transition that avoids congestion and customer frustration. It must be emphasized that the customer is the centre and the target of the energy transition.

1.5 Limiting revenues of inframarginal generators

Q 1. Do you consider that some form of revenue limitation of inframarginal generators should be maintained? ***Yes/No***

	Yes
X	No

Q2. How do you rate a possible prolongation of the inframarginal revenue cap according to the following criteria:

As following 

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

Do you have additional comments? ***3000 character(s) maximum***

The Council regulation 2022/1854 was only approved as a short-term emergency solution and should be limited in time to avoid causing legal, regulatory, and business uncertainties for operators and investors.

The energy industry recognises the significance of providing affordable electricity to various customers, however, it must be cautious not to harm climate goals or compromise electricity security through misguided interventions or signals. Therefore, **Eurelectric is strongly opposed to the extension of any form of revenue limitation of inframarginal generators for several reasons.**

First, **it fragments the European electricity market**. We refer to "market fragmentation" as opposed to "market integration" which has been the goal during the last 25 years. As we have seen with the Council Regulation 2022/1854, where we assisted to an uncoordinated implementation from the Member States that seriously undermined the integrity of the electricity market. For example, in Romania, the implementation of the cap was also translated in a surcharge on energy exports, which discouraged free trading across national borders.

Secondly, an inframarginal revenue cap **affects producers' incentives to increase production and lead to less production and less available flexibility** and, in general, eroding the signals for an efficient dispatch. In France, some hydropower assets with small reservoirs are affected by the cap. This cap, even though it only applies to 90% of rent, has altered bidding strategy on energy markets and caused some unintended consequences, such as distorted dispatch due to the difference in treatment between energy revenues subject to the cap and reserve revenues that are not, and between generation during the cap period and generation outside of it. Indeed, the current income cap is particularly challenging for flexible assets, such as hydropower with reservoirs.

Thirdly, the implementation of the cap raises **significant implementation challenges**. This has been clear with the experience of the recently adopted cap on inframarginal generators. Here, the lack of guidance from the Commission and the possibility for the Member States to extend the measure to supposed revenues that have not actually been realised had been particularly problematic. Not to mention all the uncertainty linked to the averaging period chosen for the application of the cap (transaction-per-transaction or a weighted average), the treatment of buyback, the different market revenues considered, the treatment of proxy hedged volumes.

Fourthly, the cap is already **breaching investors' confidence and disincentivizing crucial investments needed in RES & low carbon capacities** to reach EU decarbonization objectives. Integrating this badly designed tool in the European Electricity market design review will only increase even more the investors' uncertainty.

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

	Member States
X	EU

Do you have additional comments? 2000 character(s) maximum
Eurelectric is opposing having a revenue limitation of inframarginal generators. Nevertheless, if such an instrument is to be extended; **the modalities of the tool should be uniform across the EU**. The implementation of the Council Regulation 2022/1854 shows us a cautionary tale. Indeed, the current patchwork of national implementation measures is harming the integrated internal electricity market and undermining investments in much-needed RES and low-carbon infrastructure. Across the EU, Member States took advantage of the numerous derogations to implement the cap differently in terms of the cap level (I.e. such as CZ, ES, FR, GR, IT, PL just to cite some decided to differentiate the cap per technology and/or lower the cap significantly) and of the implementation duration (I.e.. BE, ES, HU, RO, SI and others extended mechanism well beyond the deadline foreseen by the Council Regulation). Not to mention the revenues considered by the cap, which is also a very divergent issue from one State to another. For example, in some Member States, the cap on revenue is applied for PPAs to fictitious market-based revenue, causing producers to pay excess revenue not received and harm investor confidence in renewables. Being calculated on a fictitious market price, this leads to an overestimation of PPAs revenue subject to the cap.

If this type of measure is not the right way forward, this further differentiation across the European countries is even more detrimental. Therefore, Eurelectric does not support the extension of any form of revenue limitation of inframarginal generators in the long-term revision of the electricity market design. **If a prolongation is foreseen, it is paramount that the modalities are uniform across the EU while its implementation should allow for a portfolio risk management approach and for sufficient flexibility to adapt to the**

different national and corporate realities in order to avoid capturing a same revenue twice.

Q.5. How can it be ensured that any revenues from such limitations on inframarginal revenues are channelled back to electricity consumers? Should a default approach apply, for example, should these revenues be allocated to consumers proportionally to their electricity consumption? *3000 characters*

➔ *No answer*

2. Alternatives to gas to keep the electricity system in balance

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

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

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?

	Yes
X	No

- **If yes, please explain.**
- **If no, do you have additional comments?**

Eurelectric considers that the short-term markets currently work well and should not be changed. However, we would like to highlight that improvement should be made in the current implementations of market rules in day-ahead (DA) and intraday (ID) especially with regards to transparency of integration projects and market participants consideration.

The current price crisis and the obstacles to the energy transition have nothing to do with the design of the short-term electricity market. The crisis is caused by high gas prices. This raises the issue of how consumer prices could be hedged against such developments and is at the core of the current discussions.

The spot price formation in the wholesale markets based on merit order and marginal pricing ensures short-term optimisation of assets and contractual arrangements and efficient price signals for the operation of the energy system.

Any political or technical measure trying to hinder this essential feature will result in distortions which must be fixed with more regulatory interventions and hence blur the price signal to efficiently manage the electricity system and to promote investments in a secure and affordable way across Europe.

Nevertheless, we would like to stress that **current DA and ID market functioning could be further improved, especially with regards to transparency on ongoing integration projects and future considerations**. Every change must be thoroughly assessed with regards to its impact on market & algorithm functioning and on market parties .The upcoming priorization of projects should consider the foreseen benefit for the market functioning.

Specifically, we would like to highlight the following issues we face currently:

- **pressure on implementation of cooptimisation in balancing market**, while its actual use is questioned by both NRAs and TSOs;
- **implementation of Intraday Auctions** at Pan-EU level in addition to ID continuous trading;
- **go-live of 15 min MTU in SDAC**, which is accompanied by uncertainty with regard to products accommodated. MPs need certainty that their opportunities to hedge and offer products won´t decrease (by implementing limitations on multiple block bids/orders, increasing paradoxically rejected bids or implementing non-uniform pricing).

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

The EU electricity and carbon markets function well together and complement each other in shaping the wholesale merit order, by prioritising the dispatch of the least emitting technologies, with the lowest variable cost.

The latest EC report on the Functioning of the European carbon market emphasizes the continuous and deep decarbonisation of the electricity industry. The power sector remains a leader in CO_2 reductions, its 2021 emissions being 8.1% below 2019 levels, for similar demand.

The ETS is central to the transformation of the generation mix. It contributed to the fuel switch towards increasingly efficient & carbon neutral sources of generation, while accelerating the phase out of highly emitting capacities.

A higher penetration of decentralised, variable sources of generation requires among other, a ramp up of long-term storage capacities and technological breakthroughs. Currently, 95% of EU's storage capacity is represented by pumped hydropower storage, ensuring firmness, flexibility and reliability needs.

The recent political agreement on the ETS Directive seems to have included "renewable technologies and energy storage technologies" in the list of projects supported via the Innovation & Modernisation Funds. However, it is important to note that these funds' envelopes are linked to the auction of allowances and the carbon price. Currently, there is high demand for support through the Innovation & Modernisation Funds, most calls being over-subscribed. Considering the increased scope of the two funds and the financing of RePowerEU through the Innovation Fund it is necessary to look for complimentary sources of funding. According to the abovementioned EC Report, the total auction revenues between January 2021 and June 2022 amounted to EUR 51.7 billion. Member states are now expected to use 100% of ETS revenue for climate projects, it should be an increased scope for receiving support in this direction.

An electricity market design that supports an efficient transition towards net-zero needs to provide a market-compatible investment framework for both RES & low-carbon technologies, and firm & flexible resources (including demand-side response & storage), which are capital-intensive. Additionally, the market design must maintain the adequacy and security of supply and meeting evolving power system requirements, in view of decentralisation and increasing flexibility & firmness needs.

A stronger framework to support these investments, foster their timely delivery and reduce financing costs, is needed to meet decarbonisation objectives while maintaining high standards of security of supply, ensure affordability, reduce dependence and address identified system needs. Long-term contracts will play a critical role to support large-scale investment in RES and low-carbon (such as nuclear and CCS) technologies which are capital intensive, including at consumer level to electrify uses and develop decentralised resources.

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)?

x	Yes
	No

Do you have additional comments?

We support that a closer to real-time Gate Closure Time (GCT) would improve cross-border intraday (ID) market functioning. It allows the market participants to better balance surpluses/shortages that are for example caused by changing weather conditions. In any case, European rules about this must be compulsory and homogeneously applied across Europe to ensure a level playing field between countries.

At the same time, some design elements for the European Balancing mechanisms would need to be adjusted. In particular:

- According to EB GL, TSO cannot take any balancing action if the market is open. In Bidding Zones where standard balancing product RR is used by the TSO, the ID market cannot be open until 30 minutes before real time because RR has a Full Activation Time is 30 minutes.
- In addition, TSOs use the additional time window of 30 minutes to collect the market participants' bids run their model send all the data to the TERRE platform while the clearing of TERRE platform for RR product is 35 minutes before real time.
- Moreover, GCT of bids of the standard balancing product mFRR is 25 minutes before real-time, obliging market participants to split liquidity between the intraday and balancing markets in countries where RR is not used and local intraday GCT is 15 minutes before real time.

Therefore, a trade-off needs to be found between the improvement of ID market functioning, the well-functioning of the Balancing schemes and TSOs operations needs. It may ultimately not result in a GCT of 15 minutes before real time but still below 60 minutes. To do this, TSOs should be transparent about their operation needs.

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

x	Yes
	No

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

We see only advantages. **Having all liquidity pooled together in countries where several market operators co-exist would be beneficial for the overall welfare.** This principle should not depend on the availability of cross-border capacities.

If you refer here to congestion management services, it should be further assessed as there is no fit in all market realities (e.g. requiring locational information).

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? What would be the advantages and drawbacks of such approach?

	Yes
x	No

We do not see the need to implement compulsory rules for non-regulated physical assets or to impose unnecessary burden to trade or limiting opportunities to trade either bilaterally or via organized markets.

There is a natural incentive to efficiently trade in day-ahead for non-regulated physical assets either under OTC arrangements or directly exposed to spot. They effectively use short-term markets to honor commitments of physical delivery in the most efficient way while guaranteeing variable costs of physical assets are recovered. Furthermore, this behavior allows flexibility disclosure of all kinds of assets.

Moreover, the REMIT regulation already ensures that market prices reflect the "competitive and fair interplay between supply and demand" and are not manipulated (e.g. through capacity withholding practices).

Finally, we consider that the day-ahead market currently works well and should not be changed. If the question of bidding behaviour of assets subjected to support schemes could be relevant, we believe that the design of these schemes should be adapted to provide the right incentives for optimal dispatch rather than implementing this compulsory rule.

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 do not see any advantages of having further locational and technology-based information in the bidding in the market. On the contrary, unit-based bidding results in a more costly and inefficient bidding process and has no benefits neither for market players nor for regulators. Market surveillance by regulators (such as oversight of capacity withholding practices) is already performed even with portfolio bidding without mandatory participation rules.

This evolution would go against the principle of zonal market where any asset contributes to the balance of a bidding zone regardless of its location and type.

However, if the concern is on congestion management, in case of network constraints, it is important for network operators to have the necessary locational information needed for an efficient congestion management. SOs will notably need such information from flexibility service providers to optimize the use of flexibility to solve congestion on their network. **At the same time, we support a reinforcement of a detailed physical nomination of schedules to the SO (crucial for redispatching actions and security of supply).**

Finally, we similarly relate the benefits of technology-based information on the design of market products. Today, we can reflect technological constraints in block orders, exclusive groups and linked block orders. Those products are essential in bidding strategy for pump-storage hydro, battery, thermal generators, etc. While the current NEMO's limits might not be restrictive today, we anticipate that the availability of those products should further increase to reflect the flexibility required by renewables integration or to sustain finer time granularity (as the 15' MTU) in day-ahead and future intraday pan-European auctions.

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

We welcome recognising the role flexibility assets & services will play in facilitating the energy transition. W**e find the majority of the work on this development should be covered in the forthcoming Network Code on Demand Response (which should be accelerated) and by ensuring proper transposition and implementation of the relevant articles in the Electricity Directive.**

However, there are several areas which could be improved through the market design to increase the uptake of demand response and aggregation offers:

- **An increased rate of the deployment of smart meters.** This will allow more customers to understand and adjust their consumption, and where intelligent meters are deployed, allow SOs, suppliers, and aggregators to automate flexibility & demand response.
- **Opening of all EU electricity markets to aggregation and demand response offers**. By allowing these offers in all markets, aggregators may offer a wider variety of products, which in turn will increase demand for more flexibility assets. Capacity balancing markets should be implemented for all types of standard balancing products.
- Furthermore, **capacity remuneration mechanisms are a crucial tool to deploy ambitious storage and demand response targets reflected in NECPs.**
- Aggregated participation of explicit demand response is already being developed following the European framework. More oversight is needed from the EC and ACER to guarantee full and consistent and coherent implementation at national level.

We must consider that setting up a high level of system flexibility requires additional investment in digitalization and automation of the grid. We observe that the current remuneration schemes induce DSOs to invest only in grid reinforcement. **Therefore, we believe that the revision of the Electricity Directive should set a clear principle that any obstacle at national level to invest in digitalisation and automation of the grids in view of procuring flexibility services should be removed.**

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?

X	Yes
	No

Incentives and appropriate remuneration schemes, set by the NRAs, are needed for the efficient provisions of flexibility services. They could be improved at MS level while making sure there is no bias in either OPEX and nor on CAPEX, but only a pursuit of a long-term optimum. DSOs must be fully remunerated for the procurement of flexibility services independent from the chosen regime (CAPEX/OPEX).

There are two effects in the remuneration of SO which prevent an unbiased decision between grid reinforcement and flexibility use:

- **OPEX are only adapted with a considerable time-lag and without correcting for past developments in most national regulatory systems** as a "budget-approach" is being used.
- While **CAPEX usually and with regards to incentivising necessary and efficient investments necessarily become effective immediately** i.e., the investment is recognized by the NRA and its corresponding CAPEX per year are added to the allowed revenue. The time-lag for OPEX must be corrected at least for "new" or fast-growing items.

There should be a clear regulatory commitment to consider such costs as eligible for regulatory reimbursement to use flexibility. SO earn a regulated revenue on CAPEX which is not the case for OPEX. To compensate this, incentive mechanisms must be designed on a national level that make it attractive for SO to use flexibility and enable them to earn a return from these activities.

Both CAPEX and OPEX are essential:

- The **urgent necessity to increase capacity for the connection of new distributed generation and loads** has demonstrated in recent years that grid investments are a no-regret option. **A higher weighting of CAPEX in remuneration schemes can reduce the investment risk and provide more incentives for efficient investment.**

- **An adequate redesign of OPEX incentives to distribution grid operators will enable the integration of these resources in the planning activities of grid distribution operators and will render the most efficient outcome.**

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/No

	Yes
X	No

Rather than incorporating a new right into the Electricity Directive, the focus should remain on full rollout of smart meters across the Member States. For metering, any revision must clearly state that main meters remain the central point of measurement and submeter use remains at the discretion of the Member States. In terms of technical requirements for the provision of flexibility & storage services, smart metering systems used by SOs are capable of measuring with sufficient granularity the necessary data.

Regarding observability, well-balanced requirements for certified submeters must be established. If regulation imposes an unjustified burden to those assets or if the implementation of this regulation is through non-coherent measures, we risk of lock-in the flexibility deployment.

However, submeters may be relevant, where the main meter data granularity is not fit for the services or when multiple suppliers/aggregators coexist for the same connection. **If certified submeters are used:**

- it should be with the **consent of the SO**
- they should be **interoperable** (the data produced by the submeter can be read according to the rules and procedures of the national metering data exchange system)

Any data from submeters must be **compatible with the verified main meter reading, transmitted to the DSO in real time** and fit the market communication standards

When data from submeters are involved in DSO responsibilities, they should meet the same technical, metrological and legal requirements (e.g.EU Measurement Instruments Directive) as the main meter. If submeters are used for flexibility, any offsetting effects from other devices behind the same main meter must be prevented – the flex must materialize at the main connection point and the DSO must be informed as they affect the distribution system and must not endanger the system stability.

Finally, we believe that **the details on the role and use of certified submeters should be set in the future network code on Demand Response**.

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? *Yes/No*

	Yes
X	No

Shifting energy over (peak) times is being done by market participants and is based on energy prices per Market Time unit of 15 minutes that are the result of intraday trading. Any intervention in this aspect of the market can only result in inefficient decisions and higher costs for consumers. In addition, any new incentive models should be rigorously assessed against market trends, be proportional, and ensure there is a real need and justification for such schemes in terms of system operation, overall efficiency, and level playing field.

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? *Yes/No*

	Yes
X	No

We do not believe that demand response requirements which would apply in crisis periods should be codified in European law - apart from those already foreseen in the Risk Preparedness Regulation and the Emergency and Restoration Network Code. Situations like the current price crisis are singular in nature and require tailored assessments and measures to address each situation individually.

Furthermore, **developing market-based solutions to promote demand reduction can prevent these crisis situations before they occur and can spur further investment into flexibility assets**. Articles 13, 15, and 17 of the Electricity Directive already address the rights of aggregation and demand response participation in the market. Before considering additional legislation, we feel **the Commission should focus on ensuring the proper transposition, implementation, and enforcement of the existing Articles.**

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?

X	Yes
	No

Yes, more could be done to reduce barriers to demand response participation in existing markets, most notably by ensuring proper implementation of the principles defined in Articles 17 & 31 of the Electricity Directive.

One of the most striking examples of a flawed implementation can be observed in Romania, where the aggregator framework (as per Chapter III of the EU Electricity Directive) has been completely misinterpreted. While the EU Electricity Directive states that aggregators must be allowed to participate in all markets, including independent aggregators (which are defined as aggregators that are "not affiliated to a supplier or any other market participant"), Romania has interpreted this as meaning that only independent aggregators (an aggregator that is a completely separate entity from a supplier) should be allowed, by defining an independent aggregator as a "market participant involved in the aggregation and not related to its customer's supplier".

Another example of interventions not sufficient to involve concrete DR participation is the example of the Italian Capacity Market, which envisaged no participation by DR units as a result of the auctions. In the Italian Capacity Market, aggregators are not paid for capacity. Instead, participating customers' suppliers receive a rebate on capacity payments which they may pass on to customers. Therefore, to participate, aggregators must strike deals with the suppliers, which contributes to making the aggregator business model unviable. Participation of DR units could be encouraged by removing some features of the mechanism, specifically i) demand units should be allowed to participate when they share a site with generation, ii) removing the faculty for the TSO to disconnect each participating customer, and iii) participants should be allowed to nominate customers even after the auction. / /

Also in the Italian market, the possibility of aggregation of consumption units does not really exist in any markets other than the tertiary reserves UVAM Pilot Programme (Unità Virtuali Abilitate Miste). Even in this programme, however, the possibility of aggregation did not occur without initial barriers due to administrative challenges in managing commercial relationships between aggregators and suppliers.

To address these barriers concretely, we recommend the Commission mandate Member States to consult with industry and aggregators on best practices and lessons learned.

Beyond ensuring the proper implementation of existing legislation in the Member States, any new incentive models (especially if capital intensive [such as utility scale batteries or hydro pump storage]) should be rigorously assessed against market trends, be proportional, and ensure there is a real need and justification for such schemes in terms of system operation, overall efficiency, and level playing field.

In addition to the proper implementation of existing legislation, there are two measures which can be developed in the short-term:

1) **The development of an investment framework, including capacity mechanisms, for the development of flexibility assets & services**
2) **Enable voluntary granular green certificates**, in order to allow for development of 24/7 CFE policies that incentivise storage and flexibility under a voluntary arrangement.

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? 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? ***Yes/No (4000 characters)***

	Yes
X	No

Today, power markets in the EU are based on the Energy-Only market design model where marginal pricing contributes to providing investment signals. In the future, due to significant increases of low-cost variable generation, firm capacity will hold become increasingly valuable. With the expected further growth of variable renewable generation, there is a need for capacity to cover the residual load, potentially with a less frequent utilisation than in the past. Many countries already have deemed necessary to introduce capacity mechanisms to support investment, and to provide the desired level of security.

In order to facilitate a European coordinated approach on capacity mechanism, these must be:

- Market-based (e.g. valuing availability of capacity)
- Technology neutral (open to generation, demand response and storage)
- Open to existing and new assets
- Open to cross-border participation
- Not temporary

However, despite the roll out of these mechanisms across Europe, current legislation defines them as temporary additions to the energy-only market model and state aid clearance is still required for their implementation. This can create uncertainty on their stability. As a result, **the current market design lacks a clear framework, common at EU level, on capacity mechanisms, which grants visibility and stability to investors.**

The power market should evolve to include market-wide capacity mechanisms as a core part of the market design to ensure adequacy and security of supply. Contrary to today, capacity mechanisms would be the solution by default, to which Member States could decide to opt out. Concretely, we recommend the following:

1. **Structurally embed Capacity Mechanisms in the market design through EU Regulation** to **streamline and automatise the approval process** if design requirements are met and to **remove their temporary implementation.**
2. **Develop guidelines to foster harmonisation of capacity mechanisms and simplify the approval process**, while keeping sufficient flexibility to address national adequacy needs and specificities.

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

	Yes
X	No

We don't see benefit in a long-term shift of the electricity market to more granular locational pricing. Physical context of Continental Europe (in terms of population, industry nodes, transmission and distribution network, integrated system operation and market models across Member States) is different from US, for instance.
Our concerns about nodal pricing is that it would:

- **be detrimental to the functioning of the market** (complexity that would not be compatible with current coupling algorithm) entailing simplification that would lead to a less efficient dispatch;
- **reduce market liquidity,** making hedging more difficult;
- **lead to significant risk increases that it puts on investments** (and notably on renewables that are usually more geographically concentrated). Indeed, clients/offtakers are typically not situated where generating assets are located, which can lead to significant geographical price spread risk. Investors in renewables fear that a shift to more granular locational pricing could limit the RES development in Europe, especially if the basis risk becomes impossible to manage or requires a prohibitive premium.
- **could have dramatic impacts on existing contractual arrangements** (e.g. PPAs, industrial contracts, …) or on existing assets value for a number of economic agents;
- **lead to sunk costs** (especially transitional ones), loss of a common European model in case nodal is applied only in certain parts of Europe, and loss of overall social welfare.

Instead, more granular pricing can be achieved by changing the bidding zone delineation. This process is already laid down in EU regulations. If smaller bidding zones prove to be overall beneficial for market functioning, then such reconfiguration can be implemented.

3. Better consumer empowerment and protection

3.1 Energy sharing and demand response

Q1. Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?

	Yes
X	No

In some Member States it is already possible through the creation of collective self-consumption schemes, always within a restricted geographical area, especially for existing buildings without adequate conditions to install rooftop solar PV. If such a provision were to be taken up, we would recommend that this should remain as localised as possible and be restricted based on the grid topology, where the same DSO operates. Virtualisation of flows is not energy sharing, therefore energy sharing should keep a local criterion.

This could also apply to peer-to-peer, and allocation of partial shares of the capacity of a larger generation park for the purposes of self-consumption or communities, if it fits the proximity criteria for instance, fitting in the legal framework for self-generation.

This would also support the acceleration of investment in RES, storage and energy management systems, that could be further improved with economies of scale and efficiency gains from energy sharing in more collective concepts associated to larger assets.

However, other aspects need to be taken into consideration, namely, to ensure the grid sustainability either from the perspective of remuneration or from the perspective of grid management of the loads (consumption and injection), and also regarding equity with other grid users. Such a reduction of physical volumes of energy from the suppliers' bill would imply additional administrative and fiscal complexity as well. This added complexity would entail costs which could exceed the benefits for final customers.

It's important that when energy is allocated between facilities connected at different points in the grid, the applied grid tariffs reflect the grid use. In particular, these should be set in a non-discriminatory manner and promote a fair sharing of costs with consumers that procure their supply with other market instruments e.g., through retailers.

Q2. If such a right were introduced:
(a) Would it affect the location of new renewable generation facilities?

X	Yes
	No

If such a right were introduced, RES would only be built in the best suited locations par technology.

(b) Should it be restricted to local areas

X	Yes
	No

As mentioned above, we believe if this right is to be implemented, it should be as localized as possible and across a zone operated by the same DSO. By living, acting or working closely to a generation asset, participants are more likely to be motivated by energy sharing

(c) Should it apply across the Member State/control/zone

	Yes
X	No

As mentioned above, we think this should be as localised as possible to reduce the strain on grid infrastructure and minimise the cost to the distribution or transmission grid. Cross-state application should not be a priority as it can be very complex, possibly requiring full harmonisation of tariff and other market operation rules.

Q3. Would you support establishing a right for customers to a second meter/sub-meter on their premises to distinguish the electricity consumed or produced by different devices?

	Yes
X	No

We would prefer that the main meter remains the central point of measurement for settlement and balancing purposes and feel that right is too strong a term here. Sub-metering generally comes in three varieties: 1) regular meters behind the main meter which are operated by the main meter operator (generally the DSO); 2) devices which are connected to their manufacturer, typically via the internet; and 3) home automation systems. Our members commonly agree that the first type of sub-meter is the most reliable.

In case there is a need for separate electricity contracts (supply/flexibility) for a certain equipment (e.g. EV charging point or solar PV panel), it should be separated as a separate metering/consumption point from the rest of the electrical installation (when feasible). This means there are two separate metering/consumption points with their own main meters that are handled according to the normal procedures (e.g. data exchange, contracts and billing) in the national retail market. This also requires that both electrical installations remain clear and safe and follow all the nationally set requirements for electrical safety. And as mentioned in our response to the first question in this section, the reduction of physical energy volumes will also add administrative and fiscal complexity to the transaction.

Certified submeters may be appropriate if the telemetry capabilities of the meter do not match with the requirements from a specific product or in case there are multiple suppliers. Charging points within places with public or semi-public access (e.g. charging points from a specific CPO in a hotel, or shopping center) are a very clear example where submeters are already applied (and they are embedded in the asset itself) and used adequately to compute the partial load of those assets and the net load of the connection point to properly process settlement and billing.

3.2 Offers and contracts

Q4. Would you support provisions requiring suppliers to offer fixed price fixed term contracts (ie. Which they cannot amend) for households?

	Yes
X	No

We are not welcoming of any legislation which regulates which types of offers our suppliers must offer in the market. Over-regulation hampers the development of innovative offers which meet the needs of our customers. What is key for us is that the market remains open so a variety of offers can be available to customers to match their needs and risk profile. We also would raise the point that fixed price contracts do not guarantee a less expensive electricity price for customers, but merely price stability over the duration of the contract.

However, if the proposed rebalancing of Article 11 may not be avoided, we would require the following terms be included in order for suppliers to remain competitive in the market:

1) The obligation to offer fixed priced contracts, with hedging supporting those prices, **must be paired with the right of suppliers to charge cost-reflective early termination fees.** (amending Article 12.3 from a derogation right of MS to an explicit right of suppliers when consumers voluntarily terminate fixed price contracts). Following this recommendation, we would also suggest that the methodology for determining these fees be set by the NRAs, ensuring that they are applicable to all fixed price contracts and that the collection of these fees is ensured also in case of bad payments. In fact, in some Member States early termination fees are not applicable due to the contractual framework that does not foresee a fixed term duration for energy contracts.
2) To prevent competitive distortion, we would recommend **the removal of the supplier size reference in Article 11.1.** All suppliers should be treated equally in the market and should have the same obligations.
3) **To promote in parallel retail offers which encompass overcoming existing barriers.** Thanks to the rollout of smart meters, more variable and dynamic options could be offered in the market, including but not limited to: time-of-use tariffs, critical peak pricing, dynamic pricing, or dynamic rebates.

Q 5. If such an obligation were implemented what should the minimum fixed term be?
(a) less than one year,
(b) one year,
(c) longer than one year
(d) Other

We think this should be left to the suppliers to decide based on the conditions specific to their markets. If such an obligation should be implemented, we would recommend less than one year as a minimum fixed term.

Q6. Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts.

	Yes	No
a. Should these provisions be clarified?	X	o
b. If these provisions are clarified, should national regulatory authorities establish ex ante approved termination fees?	o	X

The obligation to offer fixed priced contracts **must be paired with the right of suppliers to charge cost-reflective early termination fees.** (amending Article 12.3 from a derogation right of MS to an explicit right of suppliers when consumers voluntarily terminate fixed price contracts). Following this recommendation, we would suggest that the methodology for determining these fees be set by the NRAs or determined freely by the supplier before signing its initial contract with the customer.

This doesn't mean that the NRAs should pre-determine ex-ante approved termination fees, which depend in a large extent of the hedging strategy of each supplier and thus cannot be pre-determined administratively. **The NRA could however further define rules and principles about termination fees to ensure that all abide by the same set of principles.**

Q7. Do you see scope for a clarification and possible stronger enforcement of consumer rights in relation to electricity?

	Yes
X	No

3.3 Prudential supplier obligations

Q8. Would you support the establishment of prudential obligations on suppliers to ensure they are adequately hedged?

	Yes
X	No

We recognise that many of the supplier exits since the initial price shock in autumn of 2021 have come as a result of poor hedging strategies and put an undue burden on suppliers of last resort across the Union. However, **we do not think that there is a one-size-fits-all hedging strategy which can be imposed at European-level.** The hedging of electricity suppliers should be in line with their customer portfolio and thusly will differ widely. Even a partial normalization of hedging strategies risks undermining retail competition and, in the end, will be detrimental to consumers.

We would recommend, at the choice of each Member State, instead a flexible resilience framework to strengthen supplier resilience and ensure customers' protections:

1) **Ensure strict implementation of Article 10 of the Electricity Directive** which requires suppliers to provide information to consumers on proposed offers, **including risks undertaken when signing a new contract.**
2) **Regular stress tests performed by NRAs** which are adapted to national specificities to verify suppliers' abilities to face major changes in market dynamics.
3) Introducing **reporting requirements towards regulators and develop standard hedging metrics** (based on the stress test from point 2), with the publication of aggregate information which is understandable to consumers.
4) **Ensure that barriers to long-term hedging and supply in forward markets are addressed** as a key prerequisite.

Q9. Would such supplier obligations need to be differentiated for small suppliers and energy communities?

	Yes
X	No

Differentiating these obligations risks competitive distortion, and regardless of the size of the supplier, market exit due to improper hedging has the same effect on the final consumer.

3D) Supplier of last resort

Q10. Should the responsibilities of a supplier of last resort be specified at EU level including to ensure that there are clear rules for consumers returning back to the market?

	Yes
X	No

Our members found the supplier of last resort mechanisms functioned well in their countries. Given the national specificities and different market conditions, **we do not feel it is necessary to harmonise the roles and responsibilities of the SOLR mechanism at European-level.**

Q11. Would you support including an emergency framework for below cost regulated prices along the lines of the Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices, i.e. for households and SMEs?

	Yes
X	No

We do not support the codification of an emergency framework for below-cost regulated prices. Regulated prices do not help customers in the medium- and long-term because:

- these **costs are often socialised through other budget mechanisms** (where they may be paying less on the energy component of their electricity bill, this cost is

often recouped through other tariffs, taxes, and levies paid by the customers who are meant to benefit from the regulated prices),
- **lead to competitive distortion** where customers do not get the best rate,
- **and distort energy efficiency and conservation signals** by removing the price signal to curb consumption in periods of high prices or high stress on the grid.

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

	Yes
X	No

Price regulation should always be limited in time and include a clear timeframe for phase out, along with clear rules about the specific situations where consumers could benefit from such price regulation.

(b)

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

Consumers at risk of not being able reach levels of basic comfort needs require targeted protection through direct support. This direct support can be used for quick relief in the energy bill (which can be electricity or other), but mostly to provide access to the needed investment in energy efficiency, self-generation (or other form of energy sharing), and other solutions that reduce the primary need for the energy required to ensure such minimum comfort needs. A regulated tariff, below cost is not the most efficient tool to use in this regard.

(c)

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

Yes, they would reduce incentives to reduce consumption in peak times. Though it should also be considered that some consumers cannot even afford to reduce further as they are already compromising basic needs (as mentioned above). Consumers that need to be protected should be provided with targeted direct support as referred above and the prices for all consumers should at least be cost-reflective and provide the price signals for an efficient demand behaviour (any intervention to set prices below cost will shield consumers from such price signals and incentivise higher demand, which would go in the exact opposite direction of what the system as a whole needs).

If the regulated price is well-structured (e.g., CZ measure for SMEs where 80% of the highest consumption from the past 5 years is covered under a regulated price, remaining 20% stays at market price), there can be some incentive to reduce consumption retained. However, we find the most effective means for incentivising demand reduction remains in a clear price signal based on the total consumption of the final customer.

Do you have additional comments? *2000 character(s) maximum*

4. Enhance the integrity and transparency of the energy market

Q1. What improvements into the REMIT framework do you consider as most important to be addressed immediately? *4000 characters*

In general, Eurelectric believes that the REMIT framework has worked well as a sector specific regime in the energy industry. Eurelectric therefore does not see the need for a fundamental review as overall regulatory stability is key for market participants. However, this said, we believe some adjustments could be considered:

- **Adapt the REMIT framework where needed to the markets and practices evolutions**:
  - **Further assess current REMIT provisions applying to system operators and investigate whether adaptions are needed** to ensure that they publish information on the asset they own or manage e.g. when market relevant depending on the size of the market, the segment they are active in and subject to the same requirements / exemptions applied to TSOs.
  - **Add the definition of Inside Information Platforms (IIPs) and 'Registered Reporting Mechanisms' (RRMs**) as well as a definition of their respective responsibilities as well as an obligation on those entities to develop a documentation to define the adequate level of requirements (in terms of performance and availability);
  - **Future proof the definition of Organised Market Place (OMP)** to ensure that capacity allocation platforms are covered.
- **Reduce the implementation uncertainty to facilitate compliance on inside information management:**
  - **Introduce a predefined disclosure threshold (ideally at EU level) to remove case-by-case assessment uncertainty:** legislators should consider that participants of energy markets daily manage huge amounts of information which may amount to become inside information (in the form of unavailability of installations) and for this reason they need to rely on pre-determined thresholds in order to quickly identify inside information, and so timely and properly treat and publish it. Eurelectric is hence of the opinion that the definition of thresholds for the publication of inside information for gas and electricity, ideally at European level (at least at national level), is of paramount importance to eliminate the uncertainty which market participants face nowadays when managing inside information;
  - **Take into account the case law feedback**: Two specific examples to illustrate this is e.g. (i) on the qualification of the "precise" criteria, i.e., mention that the "precise nature" of the information must be necessarily subject to a decision of the asset owner (or an entity that it delegates this task to), (ii) the adoption of a prudence or risk margin to the availability plans relates to commercial plans and strategies
  - if its decision and implementation is on the basis of information similar to that which any informed market participant may be likely to possess.
- **Take into account the feedback experience:** large retail customers should be excluded from the definition of Market participants: we propose to modify the definition of "wholesale energy products" by deleting the reference to "contracts

for the supply and distribution of electricity or natural gas to final customers with a consumption capacity greater than the threshold set out in the second paragraph of point (5) shall be treated as wholesale energy products" as well as to "consumption capacity". If not possible to modify the definition, we propose two alternatives:
  - o it is key to clarify the definition as nowadays the 600 GWh per year threshold creates considerable uncertainties. It should be clarified in our view that 600 GWh threshold is intended per single (consumption) plant (such as in REMIT implementing Acts), not per single economic entity (as in REMIT today); or
  - o information concerning retail large customers are excluded from inside information definition.
- **Introduce a provision in REMIT to better secure the REMIT carve out foreseen under MiFID II and incentivizing more cooperation between energy and financial regulators.**

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? ***4000 characters***

Eurelectric believes that the national frameworks for administrative and penal sanctioning are balanced systems and, thus, should not be harmonized. Hence, such harmonization would disrupt national adjusted structures in harmony with the national context.

Furthermore, the following initiatives are recommended:

- **Strengthen cooperation between energy and financial regulators by sharing best practices to ensure consistent approach to the same cases.** Indeed, if a particular monitoring, surveillance and enforcement national regime is relying on an excess of reporting burden from the market participants' side, or national requirements are overlapped with REMIT requirements, there will be inefficiencies affecting the integrity and trustiness of that particular wholesale/retail national sector. Strengthened cooperation can be achieved through for example:
  - **Introduce a prohibition on double penalties (ne bis in idem)** to avoid that firms and/or persons would be punished twice by two NRAs;
- **Introduce an obligation on NRAs and other authorities (competition authorities, ESMA) to cooperate to ensure a consistent approach to the same cases** and ensure consistent definitions in the different regulations. **Introduce the following obligations for NRAs:**
  - **Publish sanctioned REMIT breaches with key points from Authorities in English** that could be used as lessons learned for other Market Participants & facilitate compliance;
  - **Formalise the enquiry's proceedings;**
  - **Put in place alternative disputes settlement without guilty plea obligation.**
- **Ensure proper stakeholder involvement & cost-benefit analysis before introducing any changes to the REMIT framework:**
  - **Introduce an obligation for ACER to consult stakeholders on any non-binding documentation related to the interpretation and implementation of REMIT (FAQ, TRUM, Guidance).** The ACER Guidance should remain non-binding.

- **Introduce an obligation to carry-out a costs/benefits analysis before setting any additional binding measures (revision of REMIT or Implementing Acts).**

- **Facilitate compliance and reduce implementation uncertainty in the Inside Information Platform is out of service:**
  - ACER clearly states in its Guidance that in such a contingent situation the market participant is not liable for lack of publication, but should keep in mind that the prohibition of insider trading remains. Practical implication of this is that a Market Participant (MP) (1) should constantly check that actual publication occurred and (2) if lack of publication is ascertained, should not use the information on the market. These assumptions create non negligible IT requirements and, above all, generate the risk of experiencing costly system imbalances if no use of the information is possible until disclosure is ascertained.
  - Following more than 10 years of REMIT experience, the understanding of market participants is that due regard should be given to the specificities of energy markets, which are widely influenced by several possible physical occurrences/needs, which often take place close to real time, and where management of possible inside information is a frequent occurrence.
  - In order to tackle a similar situation, the Commission could consider clarifying (for instance in a recital, or in an explicit exception within article 3) that in such contingencies the MP is not liable for infringement of insider trading prohibition (while of course action should be taken if the situation persists); otherwise, it would be welcome, at least, a more explicit recognition by ACER of the possibility that MPs may keep publishing on a backup platform, including corporate website of course provided that the latter respects the same requirements as platforms. Of course, when the IIP is back in service, this is still the main platform.

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? ***4000 characters***

On data reporting, we would recommend the following measures to simplify data reporting for market participants:

- **Avoid in general double reporting of REMIT (and e.g. EMIR) reporting data to National Regulatory Authorities** either for systematic reporting or upon request including request of information; these data should be collected from ARIS by NRAs.
- **Request the collection of fundamental data directly to TSOs, LSOs and SSOs.**
- **Introduce an option for choosing single sided reporting as a common rule:** Like under EMIR Article 9 (1f), market participants that are subject to the REMIT reporting obligation shall be empowered to delegate that reporting obligation to another counterparty. The latter should bear full responsibility and liability on the reporting of the trade (other than accuracy of (counterparty) data provided by the counterparty).
- **Integrate the LNG market data reporting into the general REMIT reporting framework:** Eurelectric is supportive of the integration of the recent dedicated LNG market data reporting into the general REMIT reporting framework. This should (1) avoid that the same data be reportable several times to different reporting interfaces and (2) that reporting of LNG market data uses the same interfaces, reporting channels and automatic tools as REMIT today.

- **Improve the guardianship of RRMs:** We propose to introduce enforcement and sanction powers for ACER regarding technical and organizational requirements and responsibilities of RRMS (incl. 3rd country RRMs) similar to the role model in EMIR regarding the powers of ESMA over the trade repositories. Furthermore, taking in account the introduction of REMIT reporting fees, the portability between RRMs should be improved and a supervision power of ACER towards RRMs should be implemented.

Eurelectric pursues in all its activities the application of the following sustainable development values:

Economic Development

- Growth, added-value, efficiency

Environmental Leadership

- Commitment, innovation, pro-activeness

Social Responsibility

- Transparency, ethics, accountability

Union of the Electricity Industry - Eurelectric aisbl
Boulevard de l'Impératrice, 66 – bte 2 - 1000 Brussels, Belgium
Tel: + 32 2 515 10 00 - VAT: BE 0462 679 112 • www.eurelectric.org
EU Transparency Register number: 4271427696-87