WindEurope's response to the European Commission's public consultation on Electricity Market Design

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The transition to climate neutrality requires a regulatory framework that makes electrification the natural choice for industry and households, and passes on the benefits of renewable electricity generation to all consumers. Consumers must be at the centre of Europe's Electricity Market reform. But the reform should consider separately how Europe delivers on the long-term goal of a carbon-neutral power sector at the lowest cost for society and the short-term policy response to high power prices.

The current energy crisis resulting from the Ukraine war has put the European economy under severe strain: the EU energy market rightfully translated supply/demand imbalances into higher prices. Therefore, the new EU energy security strategy REPowerEU identified the deployment of renewables as the key instrument to increase the availability of home-grown renewable power supply, to balance out the very high energy prices and to support European families and businesses. The EU wants wind energy to make up 43% of Europe's electricity by 2030, up from 15% today. This means double the rate of wind deployment from 15 GW p.a. to 30 GW p.a.

National Governments intervened on Energy Markets to alleviate the burdens for end-consumers. They did so without a joined-up policy response to the energy crisis, leading to fragmented and uncoordinated interventions. This undermined the very fundamentals of the internal energy market leading to uncertainty on revenues and ultimately to very significant negative impacts on renewable investments.

As things stand, Europe is not building enough new wind farms and investments are down:

- Wind turbine orders are down 47% year on year.
- There were almost no Final Investment Decision in offshore wind in 2022.
- In the first 11 months of 2022 Final Investment Decisions only represented 12 GW.

Some of the policy options presented in the Commission's public consultation document are challenging and could lead to even further structural uncertainty for investors at a time when we need to accelerate renewables deployment as a matter of urgency to reduce dependency on fossil fuel imports and achieve decarbonisation targets. While we welcome the European Commission's thinking on the upcoming Green Deal Industrial Plan, and on renewables permitting to help accelerate deployment, all of this is academic in the absence of clear investment signals.

A good Market Design reform is essential to reversing the current worrying trends and must:

- Prioritise building a future-proof energy market design fit for renewable energy by mid-century. The short-term challenges linked to high energy prices would be addressed more efficiently with better and faster implementation of the existing EU renewable energy acquis.

- Confirm investment certainty in renewables and cement Articles 4 and 6 of the 2018 Renewable Energy Directive which provide visibility on volumes and support schemes' design.

- Respect investors' decision-making on renewable investments by letting them make use of all available contractual forms for power supply procurement e.g. Contracts for Difference, Power Purchase Agreements, merchant investments.
- Do not perpetuate the emergency measures on power market interventions and revenue caps on inframarginal generation beyond their original end date of June 2023.
- Keep short-term wholesale markets based on marginal pricing and the merit order while designing climate-compatible long-term adequacy mechanisms.
- Clarify grid connection rules for renewables and prioritise electricity grid build-out.

Considering the limited time for stakeholders' input to the European Commission's public consultation, this consultation response addresses in priority chapters 1-3 therein. The detailed views of the European wind industry on Electricity Market Design are available here.

Response to chapter 1 of the European Commission's consultation: Making Electricity Bills Independent of Short-Term Markets (Power Purchase Agreements, forward hedging, Contracts for Difference)

The European wind industry calls for:

- Investors to have access to a mix of long-term contract options they can combine to incentivise renewable deployment at scale e.g. Contracts for Difference, Power Purchase Agreements, forward contracts, merchant investments.
- Contracts for Difference not to be imposed on inframarginal generators, neither for existing nor for new assets, as this alters investor certainty and financial planning rationale for renewable energy.
- The new EU Electricity Market Design to recognise the opportunity for Governments to combine Contracts for Difference and Power Purchase Agreements for the same project.
- The emergency measures on power market interventions and infra-marginal generation revenue caps to end as planned in June 2023, and be kept out of the structural Electricity Market Design reform.

The central response to the current crisis is ensuring more energy supply, in particular with more home-grown renewable electricity generation. Europe's Market Design must therefore send the right investment signals to deploy wind energy at scale.

Investment certainty and stable regulatory frameworks remain the bedrock for renewables deployment in Europe. Market scale sets in those countries where Governments respect the stability of already existing and awarded support schemes and market-based arrangements, and where Governments plan ahead and provide regulatory visibility for the wind industry and its supply chain with concrete wind deployment objectives. Industry best practices points that at least five-years forward-looking auction schedules (timeline, budget, capacity) and technology-specific auction designs are desirable to attract investments in wind energy. The 2018 Renewable Energy Directive lays down the key principles in its

Articles 4 and 6. It is imperative that the revamped Electricity Market Design respects and fully subscribes to upholding this renewable energy acquis.

The EU Electricity Market Design reform should enable the development of long-term contracts (2-sided Contracts for Difference, Power Purchase Agreements, "10 year plus" futures traded on stock exchanges) to unlock the investments needed to accelerate new power capacity buildout. Long-term contracts provide energy consumers, asset developers and investors certainty and reduce the impact of short-term fluctuations in prices.

Government-backed Contracts for Difference (CfDs) have proven very effective in de-risking wind investments and building at scale by keeping finance costs low. For instance, prior to the current energy crisis an offshore wind farm supported by a 2-sided CfD had a typical electricity cost of €50/MWh due to a material cost of capital reduction impact from having revenue stability via a CfD, versus not.

Question 10 of the European Commission's consultation on CfDs suggests for them to become the exclusive instrument to invest in wind energy and other infra-marginal technologies for existing and new assets. However, this would limit investors' decision-making and sound financial planning across their energy portfolio and will drive inefficiencies at the expense of end consumers. Notably it will crowd out PPAs and merchant investments which are indispensable to the EU meeting its energy security and climate targets. CfDs' potential imposition on existing projects equals a transgression of the Renewable Energy Directive and an unmanageable regulatory risk that could lead to an even sharper decline in renewable investments. In this regard all potential risks spelled out in Q12 would be fully applicable if CfDs were to be imposed on existing and/or new, renewable generation capacity.

Question 9 of the European Commission's consultation on CfDs suggests projects under such revenue stabilisation scheme could be subject to a lifetime pay-out obligation. It is logical that after the contractual obligation between a State and a renewable energy investor comes to the end of its originally foreseen application, the developer is free to decide how to manage its power production asset within a broader company portfolio of assets. Imposing lifetime pay-out obligations on new power generation projects will drastically alter sound financial planning for renewable energy investments and is a no-go for the industry.

On renewable Power Purchase Agreements (PPAs), the European Commission's thinking goes in the right direction. PPAs have an important role to play in the energy transition in particular for the renewables-based decarbonisation of energy-intensive industries. The Market Design reform should aim at removing all remaining regulatory barriers to the conclusion of PPAs[1] (e.g. lack of permitted renewable energy projects, lack of transmission and distribution capacities and interconnectors for cross-border trade, revenue curbing mechanisms, bureaucratic red-tape, etc.) and a standardised contact template for PPAs[2]. And should maximise the number of players active and able to sign PPAs on the demand side also towards SMEs. Government and/or public banks (notably the European Investment Bank) can play a role in underwriting PPAs and addressing challenges related to off-taker credit worthiness.

Crucially, the EU should incentivise the development of Government support mechanisms that allow combining Government-backed Contracts for Difference and market driven revenue stabilisation mechanisms such as renewable PPAs.

[1] The RE-Source Platform, regrouping corporate renewable electricity buyers and developers from across Europa, has mapped out all existing barriers to corporate renewable Power Purchase Agreement per European country in the European Corporate Sourcing Directory.
[2] The RE-Source Platform, together with the European Federation of the Energy Traders (EFET), a standard contract template for corporate Power Purchase Agreements which is today available in 6 European languages.

CfDs are instruments which pay out to generators or consumers depending on the relative difference between the market reference prices and the strike price. Renewable generators still have to secure off-takers for the generated output i.e. demand for their product. While there is currently nothing in legislation preventing the combination of CfDs and PPAs, this possibility is not explicitly recognised. This prompts investors to questions whether the model is possible and compliant with EU State aid rules. The EU Market Design reform must explicitly allow the combination of CfDs and PPAs for the same project in view of their complementarity: CfDs guarantee price stability while PPAs secure off-takers for a renewable energy generator's output.

There are already cases where Government-backed Contracts for Difference are combined with corporate renewable PPAs. This is the case of the Seagreen offshore wind farm in the UK where CfDs cover part of the output of the wind farm, and a PPAs covers the remaining output. The EU framework should allow for the development of such innovative models which will ensure a cost-effective deployment of wind energy.

But this also requires a change to the EU rules on Guarantees of Origin (GOs). There is no reason for National Government to withhold Guarantees of Origin for projects that have won a Government auction. Each MWh should have a Guarantee of Origin, this will help innovation in combining different revenue streams from CfDs and PPAs which could lower the overall amount of needed support.

Alongside CfDs and PPAs, it is critical that there is some room for purely merchant investments. This is essential for electricity producers to meet their obligations under PPAs. Generators often need to buy electricity on the spot market to meet their obligations to deliver power to the off-taker under a PPA. This means they also need to sell some of their production on the spot market to have matching revenue.

On forward markets, voluntary forward hedging should play a greater role to complement other long-term instruments (e.g. CfDs, PPAs) in the market to support investments in new generation capacity. Increased use of long-term future markets will enable off takers to hedge partial or full exposure undesired price changes.

Liquidity in the forward markets is currently insufficient. Market players and Governments focus on short-term markets (products are generally 1 year maximum) and the demand for longer term products in forward markets is generally low (with exception of Nordpool) for both energy and transmission capacity. Even on the retail side, consumers do not usually sign contracts longer than 1 year. The uncertainty of electricity price development and nationally-driven regulatory changes remain a significant barrier to enter into long-term contracts, in particular the uncertainty related to regulatory interventions. There are also very few off takers with adequate credit rating. This makes difficult for suppliers to enter into long-term contracts/agreements.

Hence, the European Agency for the Cooperation of Energy Regulators (ACER) and the European Commission should prioritise the finalisation of forward markets' integration as per the EU market coupling regulatory acquis. In addition, complementary measures to short-term markets such as contracts for long-term price stabilisation that factor in the price fluctuation in wholesale markets (Contracts for Difference, Power Purchase Agreements, hedging on forward markets) will continue to be necessary moving forward.

On emergency measures and infra-marginal generation revenue caps the European Commission's consultation suggests for such measures to become a structural part of the revamped EU Electricity Market Design. This should not be the case. Today's energy crisis was not caused by the current design of the internal Electricity Market. The market has played its role by revealing a mismatch between energy supply and demand. The crisis underlines how Europe has failed to deploy renewables in line with its own decarbonisation targets so as to be prepared to mitigate the impacts of geopolitically-driven energy supply shocks.

In this regard **it is the transposition of the EU energy acquis at national level by the EU-set deadlines e.g. Clean Energy Package, and proper monitoring by the European Commission on Member States' performance that are far more critical than embedding short-term emergency rules into the structural reform of the Electricity Market Design.**

The implementation of the infra-marginal revenue cap measures has also been extremely messy and uncoordinated. Governments have largely deviated from the Commission's proposed uniform cap of €180/MWh and several of them have also failed to factor in hedging or virtual power purchase agreements meaning that they are in breach of the rule whereby the revenue caps must apply to realised profits only. Renewables investors in those markets expect significant losses. And the emergency measures have not stopped additional measures from being applied, such as new taxes coming on top of revenue caps.

All of this has already resulted in uncertainty on revenues and to very significant negative impacts on renewable investments and deployment in 2022. The application of the EU emergency rules on power market interventions and the revenue caps on inframarginal generators should come to an end by June 2023 and should be kept out of the EU Market Design reform.

Response to chapter 2 of the European Commission's consultation: Accelerating the deployment of renewables

The European wind industry calls for:

- Europe to prioritise investments in electricity grids and clarify rules on grid connections for renewables in the revised Electricity Regulation.
- Clarify the regulatory regime for offshore hybrid power plants on cross-border grid connections, congestion revenue allocation and management.

The Electricity Market Design reform should serve as an opportunity to improve existing rules and remove bottleneck to help accelerate renewables deployment.

The **accelerated deployment of electricity grids is an absolute priority for renewables deployment going forward**. Europe has underinvested in its electricity grids in the last decade. System operators, renewable asset developers, technology suppliers and end-users need deeper cooperation since the early design stages to accelerate development of the power grid and, where appropriate, renewable hydrogen infrastructure. Permitting rules for power grids should be clarified and aligned between EU, national, local authorities so that the required infrastructure can be unlocked.

National Regulatory Authorities should create targeted mechanisms to minimise grid built-out delays in line with national electrification and decarbonisation targets. Transmission and Distribution System Operators (TSOs and DSOs) must quickly release grid capacity for renewables with temporary connection contracts subject to operational limitations (until build-out is on track) and with immediate grid optimisation projects that can be fast tracked additionally to ongoing grid expansion or reinforcement.

Member States should design national or regional auctions for renewables co-located with electricity storage or with demand (e.g. electric vehicle charging stations, combined renewables plants, renewable hydrogen) in highly congested grid areas or weak grid areas.

TSOs and DSOs should design and procure flexibility and grid support services with a long-term perspective (based on long-term contracts and technology-neutral auctions e.g. UK Stability Pathfinder programme) in line with climate neutrality targets to incentivise investments in clean flexible assets. To make flexibility investments viable, service providers should be adequately remunerated for (1) developing assets with such capabilities, (2) reserving power to be available to offer the service when required, (3) the energy used to provide each service.

Grid connection regimes under the Clean Energy Package are currently very unclear on the conditions under which TSOs and DSOs can refuse grid connection access – this should be improved.

The Market Design reform should ensure the expandability of offshore grid. Uncoordinated and non-harmonised technical requirements and the uncoordinated selection of HVDC system design may hinder, if not block, the expansion of HVDC systems and thus the integration of offshore renewables.

As Europe moves from point-to-point connections towards more complex HVDC systems (including multi-terminal HVDC) it needs a new set of technical requirements based on the operational experience of relevant projects. DC connection point technical requirements will be needed as part of the NC HVDC for the same HVDC infrastructure to be developed by different manufacturers in different timeframes (multi-vendor HVDC systems). Interoperability of assets forming meshed DC connections is also very important. Interoperability requirements should be the core part of future DC side requirements.

European market rules should **enable investment in offshore hybrid assets** by appropriately sharing risks, costs, and benefits between developers, grid operators, and society. Offshore wind could meet 17% of Europe's power needs by 2050. But this cannot happen with today's approach to grid development and Market Design.

In particular, market rules must empower developers and TSOs to connect offshore wind farms to two or more markets, saving space, resources and helping the balance the energy system. These offshore hybrid assets could be up to one third of all offshore wind capacity by 2050.

The long-term market design should enable the co-existence of operating offshore hybrids in their own "offshore bidding zone" or in their "home-market" bidding zone according to national circumstances.

o For the Offshore Bidding Zone set up it is crucial that Art. 19 of the Electricity Regulation allows for congestion revenue distribution to wind developers. This revenue sharing will not lead to cross-subsidisation from grid charges or overcompensation. And it is necessary for projects coupled with renewable hydrogen.

o For the Home-Market set up it is crucial to allow exceptions from the 70%-rule (Art. 16) for the entire lifetime of the project.

o Regardless of the market set up, the European Commission should table proposals for a Transmission Access Guarantee (TAG) that ensures that e.g. offshore wind farms are compensated when congestions occur in the electrical systems which the offshore hybrid is connect to and TSOs reduce interconnection capacity to solve such congestions.

A Transmission Access Guarantee (TAG) could mitigate the "volume risk" for generators in offshore hybrid projects, but the European Commission should further clarify its application and adjust it to also cover the "price risk" directly attributed to the hybrid setup of the project. Moreover, the TAG should be best used in combination with other compensation mechanisms, such as congestion revenue distribution.

TAG addresses the economic risk that offshore generators face when the TSOs reduce the transmission capacity allocated to the market to ensure system reliability (operational deratings). While we consider TAG a good solution to address the "volume risk" for offshore wind farms (OWFs), it could be further improved. With the existing formula, TAG will undercompensate OWFs when the value of prospectively curtailed volumes in the day-ahead market is significant. This can be corrected by including the prospectively curtailed volumes in the compensation mechanism.

The European Commission should clarify what would trigger the compensation mechanism of the TAG. It should be when the total interconnector capacity is lower than the installed OWF capacity to ensure that all the derating induced risk is compensated and that it works for different hybrid configurations. In certain cases, a price drop in the OBZ may be induced by an operational derating.

Furthermore, the reliability of the TAG compensation is key for offshore wind investors. If the TAG compensation is paid from congestion income alone, it is essential that it is classified as priority use of congestion income.

However, TAG will not be enough to incentivise the first offshore hybrid projects. Offshore hybrid projects today are riskier than connecting wind farms to individual countries and building separate interconnectors, although they bring significant socio-economic welfare benefits such as increase in market integration and decrease in system costs. To unlock the potential of offshore hybrids it is key to hedge both volume and price risks. Options such as redistribution of congestion income, capability-based CfDs or a combination of solutions should be used to complement TAG and hedge the offshore generators against "price risk" as well.

The integration of offshore renewables effectively at sea basin level remains challenging. Several technical aspects require further technical and regulatory work including: the development of planning standards for offshore high voltage direct current (HVDC) grids, the standardisation of assets and equipment, specification of HVDC systems and operation rules and connection network code requirements for offshore power generation modules and HVDC systems connecting to onshore transmission networks. These issues should be addressed by amending the existing Connection Network Codes (CNCs) accordingly.

Response to chapter 3 of the European Commission's consultation: Alternatives to Gas to keep the Electricity System in balance

The European wind industry calls for:

- Keeping short-term wholesale markets based on marginal pricing and the merit order.
- Designing climate-compatible Capacity Renumeration Mechanisms allowing domestic and cross-border demand side response, storage, and renewable generators' participation.

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Short-term wholesale markets (based on the marginal cost approach) are very efficient in reflecting the real value of electricity at a given time. Short-term wholesale markets should remain the main mechanism for ensuring cost efficient power plant dispatch and settlement of electricity market contracts. The EU Market Design reform should safeguard the functioning of liquid and efficient short-term markets. The reform should ensure the functioning of short-term markets is not distorted by revenue caps and other uncoordinated market interventions from National Governments.

Europe also needs to enhance the availability of flexibility products in the market specifically targeting storage and demand response. Short-term market signals can help in incentivising flexible behaviour (e.g. balancing market pricing, peak shaving) even though there is room for improvement in their current deployment to increase the access to variable renewables. However, these will not be sufficient to drive all necessary capital investments in flexibility capabilities and new flexible resources. This will only take place if the right long-term investment incentives are in place.

Availability of grid connection points allowing additional capacity (co-located assets) is a crucial way of enhancing flexibility. Project developers should have the possibility to install more total co-located capacity compared to their grid connection.

- Support in periods of negative prices should be capped. Planners should focus their efforts to foster new investments in flexible technologies by other future-proof means aligned with decarbonisation goals i.e., adapting markets to more flexibility requirements or procuring flexibility services adapted for renewables. Support for production in times of negative prices should be phased out hand in hand with regulatory requirements that increase system flexibility on supply and on demand side.
- Most EU Member States do not have a different tariff for energy storage, so they pay to the TSO for charging as well as injecting in the grid. This double grid tariffs for storage should be phased out.

Market-based curtailment products can quickly alleviate grid scarcity and structural congestion and can create flexible resources in line with the decarbonisation targets. For instance, to reduce the volumes of curtailed renewable energy, governments can set up limited centralised or regional auctions for renewable assets integrating storage units in zones that are identified as congested. The winning assets should have the option to be awarded CfDs that can remunerate both the generation and the storage unit. Existing assets willing to upgrade should also be eligible for such auctions if installed in such zones.

Regulatory frameworks should incentivise implementation of short- or medium-term solutions that lead to a total cost saving (TOTEX being CAPEX + OPEX) in addition to more traditional long term focused investments. There is a bias towards investments in new grid development (CAPEX-based investments) instead of grid optimisation technologies; TSO revenue is generally proportional to the volume of its CAPEX-based investment, but not increased in case of savings in TOTEX. Grid optimisation technologies can maximise the use of existing transfer capacity resulting in TOTEX savings or even to the deferral of new capacity requirements in the long term (so potentially lower costs paid by the consumers). TSO should be incentivised based on TOTEX-savings instead of a simpler CAPEX based approach. Adequate risk mitigation policies should be designed also for TOTEX-saving solutions.

The degree of demand response in a system will have huge implication on the estimated cost in future power system. It is important to enable fair market access for demand response and service providers. Deployment of demand side flexibility has so far been impeded by outdated market rules, insufficient market access for service providers and ineffective price signals. Demand response should have non-discriminatory access to all markets.

The current concern to shiel consumers against high energy prices should not deprive them from the right to participate in energy markets with dynamic price contracts on a voluntary basis. This includes providing customers information on actual time of use at near real time and the right to respond to price signals, as well giving consumers the right to sell flexibility independently of any contractual arrangements to procure energy, directly or through an (independent) aggregator.

TSOs should report on redispatch and countertrading measures they undertake, including underlying costs, and the level of effectiveness and openness of market-based curtailment or re-dispatching mechanisms to all energy resources. In turn, the creation of liquid and efficient markets and the deployment of demand-side flexibility resources will reduce the need for additional measures to guarantee system adequacy.

At the same time, Europe needs energy security instruments that safeguard climate action. **Long-term adequacy mechanisms (Capacity Remuneration Mechanisms) will be needed, notably to unlock the potential of electricity storage**. They should be limited to providing the required adequacy based on a system adequacy assessment and designed to minimise distortive impacts on energy markets. Capacity Remuneration Mechanisms design should allow for cross-border solutions and should be fully consistent with the delivery of climate neutrality.

Capacity Remuneration Mechanisms should be technology-neutral, based on a system adequacy assessment, and allow domestic and cross-border demand side response, storage, zero-carbon and renewable generators' participation. And they should meet an emissions performance standard starting from the European Investment Bank (EIB) lending policy standard and decreasing over time so that Europe manages to decarbonise its energy system already by 2035.