CONSULATION RESPONSE

Energy Traders Europe response on the review of electricity market arrangements (REMA) second consultation

Brussels, 07 May 2024

Executive Summary

We share DESNZ's view on the central role of markets at the heart of GB's future electricity system, and we appreciate the extensive stakeholder involvement during this second consultation on REMA and throughout the process.

In the last volatile years, electricity markets proved effective and resilient in ensuring a secure electricity supply to consumers while providing incentives for clean investments on the road to carbon neutrality by 2050.

Short-term wholesale markets have ensured a cost-efficient power plant dispatch, use of transmission networks and settlement of electricity contracts. Forward markets have shielded consumers from short-term volatility in the market. Moreover, they have sent a powerful signal for investments in renewable energy, energy storage and consumer-driven solutions, including PPAs and long-term hedging.

We agree with DESNZ that retaining marginal pricing across the wholesale market and future-proofing the CfD scheme are the best way forward. Other key elements that should be implemented are:

- Recoupling the UK exchanges in day-ahead to provide a more robust price signal. EPEX SPOT and N2EX should re-merge their order books and organise a single auction in day-ahead as soon as possible.
- Delivering more efficient cross-border trading arrangements with the rest of Europe. As also recognised in the REMA consultation document, interconnectors are a significant source of flexibility and security of supply. This would include intraday and long-term trading on the NSL cable with Norway.
- Strengthening the UK ETS and linking it with the EU ETS. It would have an enhanced role in driving the decarbonisation effort across the UK economy. It would provide an exemption from CBAM and reduce the development risk of offshore grid/cross-border infrastructure needed for the energy transition.
- Shortening the market time unit (i.e. 30 minutes at present) and moving the gate closure closer to real-time – benefitting flexible capacity and demand response.
- Consolidating the number of ancillary services markets, making information more clearly available, and enabling participation by a broader range of market participants.

We look forward to further discussing the important issues raised by this consultation with the DESNZ team.

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Consultation questions

Challenge 1: Passing through the value of a renewables-based system to consumers

1. *What growth potential do you consider the CPPA market to have? Please consider: how this market is impacted by the barriers we have outlined (or other barriers), how it might evolve as the grid decarbonises, and how it could be impacted by other REMA options for reforming the CfD and wholesale markets.*

We see great growth potential in the demand for PPAs and other kinds of long-term agreements (i.e. forward market contracts), as these play an essential role in helping both consumers and RES-E developers hedge themselves against risk. Drivers for growth include consumer demand for hedging against short-term price volatility and the need for long-term revenue stability for RES-E developers. Other factors contribute, such as corporate sustainability goals (where PPAs combined with REGOs demonstrate the green provenance of electricity use) and potential demand from green hydrogen production projects. Indeed, the current Renewable Energy Guarantee of Origin (REGO) scheme is an important enabler and pre-condition to CPPAs.

In our view, DESNZ has correctly identified the barriers to CPPA uptake – which tend to apply more generally to the uptake of other long-term agreements, such as different types of PPAs and forward market contracts. We would also highlight another barrier – the relative attractiveness for developers of two-way CfDs. The higher price received for production, the lower counterparty risk, and the lower transaction cost vis-à-vis negotiating directly with an off-taker mean that CfDs remain the preferred route to market for project developers.

To address such barriers in the European context as part of the European Electricity Market Design reform, Energy Traders Europe supported the option for Member States to implement public credit guarantee schemes for consumers to help facilitate their access to Power Purchasing Agreements. We recognise that DESNZ is not currently inclined to pursue such intervention in the REMA context. Nonetheless, we would like to point out the benefits that a similar targeted support scheme for UK consumers could provide to facilitate their access to a broad suite of long-term agreements.

- It could help **address counterparty risk**: targeted government backing in the form of credit guarantees can help consumers achieve further competitive contractual terms.
- It could also **address the contract/demand mismatch**: with the broader focus on supporting consumer access to an expansive suite of long-term agreements (PPAs, CPPAs, and forward market contracts), it facilitates consumer access to intermediaries (i.e. traders) who can aggregate deliveries and supply, and thus deliver tailored profiles to the needs of consumers.

Another measure to address the high transaction cost of PPA/CPPA contracts would be a voluntary and market-defined contract standardisation to help reduce the cost and complexity of entering into such agreements.

Lastly, concerning other REMA wholesale market reforms, there needs to be space and incentives for PPAs and various other long-term contractual arrangements, such as forward market contracts. The preferred development of generation assets should market-based, and the government should focus on establishing an improved enabling framework through policy and regulatory certainty, grid connections, grid expansion, focus on NIMBYism for onshore wind in England, and the improvement of market liquidity.

2. *How might a larger CPPA market spread the risks and benefits of variable renewable energy across consumers?*

As a reminder, CPPAs are long-term contracts where market participants purchase electricity and take on the risks and responsibilities as they hedge their positions. We expect current benefits to persist and evolve. Multi-year CPPAs secure finances in the longer term, which for renewable energy projects signals viability, and contributes to the overall security of supply. They also provide investment signals and reduce the need for financial aid to power generators. With a bigger market, there will be better liquidity, which fosters additional interest and a better distribution of risks and benefits.

As mentioned above, risks are allocated to the best-placed party to manage them. Within a larger market, this feature expectedly will remain. We recognise that compared to CfDs, there is more volatility in the wholesale markets.

3. *Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.*

We agree with some measures to sharpen price signals and improve the assessment methodologies for valuing sector benefits, such as shortening the settlement periods.

We further advocate shortening the market time unit and moving gate closure closer to real-time, which provides flexible capacity and demand response benefits.

Specifically on demand response, we previously recommended enabling more open access for demand response to various markets that would allow for a more tangible contribution to reducing need for costly network reinforcement and development, including congestion management. Demand response should be market-based only, as with demand, they effectively respond to wholesale price signals.

While demand flexibility should be encouraged, we should avoid expensive measures like demand flexibility services activation when sufficient supply is available.

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Challenge 2: Investing to create a renewables-based system at pace

4. *Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address.*

We agree that the challenges for the future of the CfD are correctly identified.

We emphasise the need for CfD evolution to tackle the non-resolved barriers to forward trading and the impacts on hedging within the various CfD designs. A competitive and liquid forward market is essential because it enables suppliers to hedge forwards and offer their customers one-to-two-year fixed-price contracts.

We also reiterate the need to address market distortions, as we support choosing a CfD model with the least negative effects on short-term dispatch and forward market liquidity, accompanied by a straightforward implementation that maintains investor confidence.

Additionally, CfDs should be used sparingly and reserved for new low-carbon capacities for which private investment is insufficient.

5. *Assuming the CfD distortions we have identified are removed, and renewable assets are exposed to the full range of market signals/risks (similar to fully merchant assets), how far would assets alter their behaviour in practice?*

In our experience, both generation and demand respond to market signals. Nevertheless, we recommend increasing the level of market exposure and improving generator flexibility so they can adapt to real conditions as a way to reduce the impact on forward markets.

6. *How far will proposed 'ongoing' CfD reforms go to resolving the three challenges we have outlined (scaling up investment, maximising responsiveness, and distributing risk)?*

We are not in favour of expanding the scope of the current CfD design to scale up renewables. It would worsen market distortions without properly addressing them, such as insufficient provision of ancillary services.

We request further insight into the implications and consequences of uncoupling CfD assets from the Balancing and Settlement code.

Lastly, vulnerability to volume risks remains under this option, unlike under a cap and floor model covering volume risks for developers.

7. *What specific gaming risks, if any, do you see in the deemed generation model, and do any of the deeming methodologies/variations alter those gaming risks? Please provide supporting reasoning.*

We agree with the identified risks in the different deeming methodologies surrounding gaming and fraud.

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While a deemed generation model may be good in theory, it would be complicated to implement in practice. We are primarily concerned with the methodology used, as it would have to be correct and accurate in determining the reference generator or deemed output.

8. *Under a capacity-based CfD, what factors do you think will influence auction bidding behaviour? In particular, please consider the extent to which developers will be able to reflect anticipated revenues from other markets in their capacity-based CfD bid.*

Under a capacity-based CfD, the paid amount is fixed and based on capacity, and we agree that developers may seek to obtain high-capacity payments within auctions. We are concerned that the volumes provided may not be promoted enough through this CfD design as the focus is on capacity, independent of market activity.

Developers may be able to reflect anticipated revenues from other markets in their capacity-based CfD bids if those markets are liquid enough.

9. *Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q25 on which actors are best placed to manage the different risks?*

In question 25, we determined that the risk distribution should include all market participants. Traders should also be considered. On the other hand, we should generally omit the government from risk management.

Both models have the potential for higher volumes of support payments, whereas we have previously argued the sporadic use of CfDs supporting new low-carbon technologies without sufficient private capital.

We also generally advocate for increased exposure of market participants to market conditions. A deemed model protects from price risks but would not cover all volume risks, while a capacity-based model exposes generators to both price and volume risks daily.

10. *Do you have a preference for either the deemed CfD or the capacity-based CfD model? Please consider any particular merits or risks of both models.*

We have no preference for either model. We support increased levels of market exposure for CfDs, as this could reduce the impact on forward market liquidity and increase incentives for more flexibility from CfD-supported producers. In our considerations for CfD models in Europe, we published a paper recommending a thorough analysis of "capability-based" and "financial CfD" models because they do not distort the short-term dispatch price signal. We also suggest investigating the "cap and floor" model with a single-floor CfD as the best way to position producers in the market while providing financial security and assisting with volume risks.

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Deemed CfDs are good in theory, but they face serious implementation difficulties, especially in determining an accurate deemed output. On the other hand, capacity-based CfDs may not incentivise sufficient provision of volume on the market.

11. *Do you see any particular merits or risks with a partial payment CfD?*

Partial payment CfDs may be a less radical option and easiest to implement without seriously undermining investor confidence. It can also be combined with CPPAs, leaving room for its market development. The actual benefits of such an option would depend on the decided split between CfD and merchant-backed output.

Furthermore, partial CfDs could be mandated or incentivised in the auction design for mature technologies. For immature technologies, where the deployment costs greatly exceed customers' willingness to pay, a partial CfD may not be appropriate.

12. *Do you see any particular merits or risks with the reforms to the CfD reference price we have outlined? Please consider how far the two reforms we have outlined might affect both liquidity in forward markets and basis risk for developers.*

Reforming the CfD reference price would involve fewer structural changes than the other CfD design models, which could lead to straightforward implementation without massively affecting investor confidence. The reform benefits would depend on the composition of the reference price, notably which market prices would be included/covered. The reform could be one approach for limiting the impact on the forward market if there is insufficient exposure to prices further down the curve.

We generally support an option achieving the balance between ensuring forward market liquidity and accounting for asset nature to guarantee a level playing field. The hybrid reference price may be easier to implement. Further analysis might be needed towards the indexation of the reference price to clear baskets of market prices in different timeframes under the hybrid approach that could provide visibility and address some of the forward market liquidity issues. However, investors may be uncertain about this option.

13. *What role do you think CPPA and PPA markets, and REMA reforms more broadly, will play in helping drive small-scale renewable deployment in the near-, mid- and far-term?*

We kindly remind DESNZ that the market is much broader, and many tools are provided for long-term hedging and incentivising forward market liquidity. We agree that CPPAs and PPAs more broadly, as well as the REMA reforms, will help drive small-scale renewable deployment in the near-, mid- and far-term. Accompanying these reforms should be improvements in ESO capabilities, such as through better utilisation of batteries in dispatch, defining products that are needed for system operation to be delivered by the market,

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improving ESO-DSO cooperation and transparency, improving weather and system status forecast, and coupling with the EU.

The main barrier to small-scale renewable deployment is the stringent credit requirements that hinder access to the CPPA and PPA markets to smaller market participants. To address the credit risk profile barrier, we promote using credit risk reduction instruments backed by public authorities, such as credit guarantees. As outlined in our response to question 1, the benefits include helping address the counterparty risk and the contract/demand mismatch.

In addition, access to different revenue streams, facilitating aggregation, and the development of local markets could help value better the system benefits of small-scale distributed renewables.

Challenge 3: Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system

14. *Are there any unintended consequences that we should consider regarding the optimal use of minima in the CM and/or the desirable characteristics it should be set to procure?*

The primary objective of the Capacity Market design should be to ensure capacity adequacy and security of supply at the lowest cost to GB consumers. To achieve this, the Government should focus on maximising the ability of different technologies to participate in the Capacity Market. Our other main request is the guarantee of foreign capacity participation in the Capacity Market.

15. *What aspects of the wider CM framework, auction design and parameters should we consider reviewing to ensure there are no barriers to success for introducing minima into the CM?*

The optimised Capacity Market should have the least distortive effects. We value the following flexibility characteristics in the CM: response time, duration of capacity provision, and location. Foreign assets should also be able to participate in the CM.

16. *Do you agree with the proposal that new lower emission limits for new build and refurbishing CMUs on long-term contracts should be implemented from the 2026 auctions at the earliest?*

In general, yes. We promote carbon neutrality.

17. *If you are considering investment in flexible capacity, to what extent would emissions limits for new build and refurbishing capacity impact your investment decisions?*

No comment.

18. *Considering the policies listed above, which are already in place or in development, what do you foresee as the main remaining challenges in converting existing unabated gas plants to low carbon alternatives?*

No comment.

19. *Do you think there is currently a viable investment landscape for unabated gas generation to later convert to low carbon alternatives? If not, please set out what further measures would be needed.*

A UK ETS design that is consistent with achieving net zero in 2050, including the removal of any thresholds for the participation of smaller generation. The design should adequately incorporate the participation of negative emissions. Ideally, the UK ETS should recouple with the EU ETS.

20. *Do you agree that an Optimised CM and the work set out in Appendix 3 will sufficiently incentivise the deployment and utilisation of distributed low carbon flexibility? If not, please set out what further measures would be needed.*

No comment.

21. *Do you agree that our combined proposed package of reforms (bespoke mechanisms for certain low carbon flexible technologies, sharper operational signals, and an Optimised Capacity Market) is sufficient to incentivise flexibility in the long-term? Please set out any other necessary measures.*

No comment.

Challenge 4: Operating and optimising a renewables-based system, cost-effectively

22. *Do you agree with the key design choices we have identified in the consultation and in Appendix 4 for zonal pricing? Please detail any missing design considerations.*

We generally support the need for sharper price signals. A zonal design may be a less radical option than nodal, where today's national market is split into several zones better reflecting network constraints.

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However, its benefits should also be demonstrated convincingly, with an assessment considering the likely impact on liquidity, the overall welfare impact, and the need to ensure predictability to prevent an impact on investor confidence. A move to a zonal design would also require revisions to existing contracts — a complex, lengthy, and costly process.

In 2019, the main lessons from our Position Paper on Bidding Zones Delineation in Europe were that the experience of the Swedish and German/Austrian bidding zones split showed the potential danger of overweighing the costs of re-dispatching and/or countertrading without balancing them with the advantages of competition and liquidity.

If there is zonal pricing there would be a need for a robust and transparent methodology defining the zones and accounting for the impacts on market efficiency, market liquidity, and overall welfare effects. Finding a balance between the need for accurately reflecting network congestion and regulatory stability is crucial.

Hence, a need to avoid dynamic reconfigurations of the zones as they would provide too much regulatory instability, which would hinder investor confidence. Deciding a re-delineation of bidding zones should only be done if and when other lower-cost, lower-impact solutions prove less efficient from a network management and market efficiency perspective.

Moreover, a sufficient lead time of at least 5 years should be given to market participants between the potential decision and implementation of zonal pricing. Organising a parallel run should also be done before the implementation.

We welcome the attention given to cross-border energy trading by engaging in international and European cooperation to minimise potential implementation risks for cross-border trading arrangements. We are looking forward to having the reimplementation of full-price Market Coupling. Indeed, if there is a serious consideration for zonal pricing, recoupling the two day-ahead prices must be a prerequisite.

Defining the number and size of the zones also raises the following questions. What will be the impact on the interconnectors? Would they be in the same or different zones? We would need to consider how to deal with cross-border capacity between zones in different time horizons (day-ahead, intraday, and forward) and how to split up long-term and daily capacity. We reiterate the following key messages on interconnectors:

- Full price coupling between GB and the EU should be achieved;
- Recoupling the two UK power exchanges in day ahead;
- The TSO should approve the feasibility of the market to benefit from the natural hedge of the transmission grid in Y+2 and Y+3.

Additionally, there would be a need for LTTRs and hedging between zones with sufficient capacity and to provide tools ensuring existing rights. There should also be ample lead time to respect the current time horizons. Another consideration would be reducing the granularity of interconnectors, currently at 60 minutes.

As for the preferred dispatch model, we continue to advocate for self-dispatch and portfolio bidding in tandem with a shorter imbalance settlement period of 15 minutes and shorter gate closure of up to 5 minutes. Self-dispatch facilitates hedging and intraday adjustments. The GB wholesale market currently acts as a central dispatch from 60 minutes ahead of real-time and compares poorly to other markets (i.e. Germany) that have gate closure closer to real-time. Therefore, there is a need to consider a shorter gate closure time in the REMA reforms.

23. *How far would our retained alternatives to locational pricing options go towards resolving the challenges we have identified, compared with locational pricing? Please provide supporting evidence and consider how these alternative options could work together, and/or alongside other options for improving temporal signals and balancing and ancillary services.*

We are in favour of retaining national pricing and implementing reforms to enhance locational pricing signals and dispatch efficiency. There is also a need to combine these changes with reforms to ESO and system operation, including providing continued incentives for network investment.

The proposed reforms would be more incremental, less costly, and avoid significant structural changes like with zonal pricing. Depending on the design selected for zonal pricing, there are high risks of split and reduced market liquidity, as has been the case in some of the European examples.

We are aware that the proposed reforms predominantly provide investment signals. We would agree to a reform package that would deliver operational benefits, such as reforms to the Balancing mechanism, a shorter ISP and shorter gate closure time. Should there be a shortening of the market time unit, like the ISP, to 15 minutes, there must be a clear distinction between the two. As for the balancing mechanism, we encourage reforms that improve competition and provide further transparency.

More particularly on the Ofgem improvement reforms on TNUoS and DUoS, we highlight the need to assess how network access is granted.

We support optimising the use of cross-border interconnectors and electricity storage. The REMA reforms should also consider the barrier to entry — the lack of financial products. Hence, we reiterate the need for LTTRs and our key interconnector messages elucidated above.

Our dispatch preference remains self-dispatch as it facilitates hedging and intraday adjustments. We are also aware that improving ESO capabilities is essential. Improvements could be achieved through better utilisation of batteries in dispatch, defining products needed for system operation to be delivered by the market, improving ESO-DSO cooperation and transparency, improving weather and system status forecast, and coupling with the EU.

24. *Do you agree with our proposed steps for ensuring continued system operability as the electricity system decarbonises? Please detail any alternative measures we should consider and any evidence on likely impacts.*

We agree with the need to ensure continued system operability through on-track reforms, some of which should be accelerated, such as a shorter imbalance settlement period of 15 minutes.

A shorter ISP could help make prices more reflective of the actual market conditions, incentivising generation and demand to frequently respond to the system status. This reform should be accompanied by a shorter gate closure to increase temporal granularity, which helps minimise disruption and reduce the costs of reforming the electricity market. Additionally, having closer to real-time gate closure allows generators' final positions to be more accurate, thus reducing the need for balancing action.

Focusing on balancing market reforms, we support bringing more competition and transparency for further system optimisation, reducing costs passed on to the consumers. We reiterate our previous position to allow electricity storage operators to bid into the balancing capacity and energy auctions, including via pooling, as it would bring additional competition. Market participants should also be allowed to link or make bids conditional to ensure the contribution of the wide diversity of capacity owners, yet again bringing additional competition.

We also raise the question as to whether there might be a need for a reserve market or any grid product needs related to balancing that could be provided by the market. We would be open to participating in a consultation examining such options.

We request additional transparency from the TSO on the system, notably on physical notifications. We are also aware that ESO faces a lack of visibility. We recommend analysing of the potential measures that address this recurring problem, notably focusing on under 50 MW assets that do not give physical notification or participate in the balancing mechanism.

Once again, we advocate for self-dispatch, as the market can resolve imbalances by itself, which can be further incentivised via a shorter gate closure time. Self-dispatch offers better trading opportunities and allows adjustments under competitive pressure much closer to real-time, which is necessary for an energy system with a higher volume of renewables. In contrast, central dispatch significantly impacts investors' ability to model potential returns from assets, which would severely undermine investor confidence. We also remain sceptical about the concrete application of the compromise option of self-commitment within a centralised model.

We recommend that ESO should seek to expand the suite of ancillary services at its availability, such as additional day-ahead procurement of balancing services. We also await the investigation results on the perceived barriers to the provision of ancillary services from co-located assets and expect more revenue visibility and investment planning from the results on the alignment of longer-term ancillary services with CfD and capacity market auctions.

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Options compatibility and Legacy Arrangements

25. *Which market actors (e.g. generators, suppliers, consumers, government) are best placed to bear / manage different types of risk?*

We believe that all market participants should be involved in the risk distribution. The government would be an essential actor in the risk management of legacy arrangements.

26. *Do you agree with our initial assessment of the compatibility between our remaining options? Please set out any key interactions we have missed.*

We agree that there is a strong interdependency between the various reform propositions. Depending on the design choices made in some of the reform options, they would be compatible with other wholesale market reform decisions.

27. *Do you agree with our approach to assessing the impact of REMA reforms on Legacy Arrangements?*

In the transitional period following reform, we agree to protect prior arrangements until their agreed conclusion date.

28. *What risks do we need to consider with regard to Legacy Arrangements, and how can they best be mitigated?*

No comment.

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