REA Response: Review of electricity market arrangements (REMA): second consultation

The Association for Renewable Energy & Clean Technology (REA) is pleased to submit this response to the above consultation. The REA represents a wide variety of organisations, including generators, project developers, fuel and power suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 500 corporate members of the REA, making it the largest renewable energy trade association in the UK.

Of further relevance to this consultation, the REA has a large number of renewable power generators who have previously been supported under the CfD or RO. This includes member forums focused on biomass power, energy from waste, landfill gas, green gasses, advanced conversion technologies and hydrogen.

The REA, in 2023, also produced our own REMA report, which is also drawn upon below. Further evidence in relation to our recommendations can be found here: https://www.r-e-a.net/resources/rea-rema-report/

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.

The CPPA market needs to evolve in parallel to market polices being considered by REMA

The REA largely agree with the Government assessment of the potential for the CPPA market to continue to have an import role in enabling the deployment of renewable capacity, especially in the context of corporate or industrial decarbonisation. However, the CPPA market should be considered a useful alternative route to market, rather than the primary policy to see the full delivery of the UK's decarbonisation target. More dedicated policy, such as the reforms being considered to the CfD and Capacity Market, will be needed in addition to addressing CPPA market barriers.

In relation to the evolution of CPPA's themselves, government will need to ensure CPPA's are competitive compared to an evolved CfD offer, so that they remain a viable alternative route to market. Government could introduce a Green Premium for the renewable generation generated within a CPPA. This additional benefit could help derisk the CPPA contract and make them more attractive. While there would be a government cost in its delivery, this modest additional payment will be cheaper than having to contract the same volume of capacity through the capacity market or CfD mechanism, given most of the expenditure would be direct from private investment. This could be considered a policy that could be developed in parallel to broader REMA proposals that will be needed to meet the level of generation capacity that is necessary.

Barriers to the evolution of the CPPA market will be addressed if Government puts in place long term and stable energy market structures.

The primary barriers to CPPA are identified in the consultation including high counterparty risk, high transaction costs and contracts/length/demand mismatches. These issues however can be addressed in private contracts if the wholesale market itself is stable, predictable, and transparent.

Government should recognise that continual change makes it unattractive for corporations to lock into long term PPA contracts. We emphasise that the main causes of the identified barriers will help to be resolved by the REMA process setting out clear and strong market policy, in a sensible time frame, as opposed to directly getting involved in CPPA design. The barriers identified are largely caused by market uncertainty, which make it difficult to design low risk, low cost or longer CPPA agreements.

REMA itself, by its nature, has introduced some of this uncertainty and a quick resolution of the process is needed to ensure the CPPA market knows how to set out contracts that are fit for the future. This also needs to be met with fewer significant code reviews and a more consistent approach to network charging, all of which makes it difficult for low risk and low cost CPPA contracts to be designed.

CPPA barriers are also caused by physical deployment barriers, in particular grid constraints and slow planning approvals.

In parallel, to delivering a stable market design, the CPPA market will also benefit from work streams that directly address the physical barriers to renewable and clean technology deployment. This means speedily addressing capacity constraints, stopping new connections in a reasonable and investable time frame, as well as speeding up planning permission processes.

Government should be using its market position as the largest procurer of power to set the benchmark for PPA design.

The CPPA market will also be advanced by Government itself using its market position to be designing and utilising PPA for public procurement of energy. The Government is the largest buyer of electricity in the country and is well placed to be both utilising PPAs and putting in benchmark agreements against which further corporate PPAs can be evolved. This would align with the Treasures previous Net Zero Review published back in 2021. [1] As such, the issuing of Government backed PPA's will ensure that market barriers are addressed, so that they themselves are secure and help evolve the market.

[1] HMT (2021) Net Zero Review Final Report https://www.gov.uk/government/publications/net-zero-review-final-report

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

A larger CPPA market will increase the deployment of dedicated generation for large industrial and commercial power users. This will ensure the costs of meeting this demand with low carbon and secure generation will fall more on the private sector rather than consumers. Construction, operation, and technical risk is therefore increasingly taken on by the developer and off taker, rather than the government. With a greater need to ensure dedicated demand is met by generation, such projects also have a clear incentive to match variable renewable generation with energy storage. This reduces industrial and large-scale dependency on wider power generation, lowering the wider impact on consumers.

However, this will only be possible if wider barriers to corporate PPA's are derisked. As discussed in question 1, this includes policy and regulatory risks (including their associated costs like grid charges), as well as the physical barriers to deployment such as grid capacity constraints and speeding up the planning process. Without this it becomes very difficult for private companies to lock into long term PPA agreements, due to the wider uncertainty present in the market.

The addition of a Green Premium within CPPA's, as discussed in question 1, could help to derisk such barriers. By helping to address these wider issues, Government would enable private counterparties to CPPAs to have confidence in being able to build systems that match generation and demand with less concern of policy, regulatory or political risk.

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 largely agree with consultation's anlysis to focus on a cross-cutting approach, rather then designing dedicated demand reduction polices within REMA. However, we reiterate the importance of having parallel workstreams within relevant government departments to ensure demand reduction is being delivered. For the most part, we agree that these interventions are not going to be delivered by wholesale market design, but dedicated policy. In particular this includes:

- Speeding up delivery of half hourly settlement across the domestic and non-domestic retail energy sector.
- Evolution of building regulations to mandate energy efficiency measures in new builds, and retrofits in existing properties at appropriate times.
- Urgently providing dedicated policy support for industrial and commercial heat decarbonisation. While recognising the contributions of the IETF and Public Sector Decarbonisation Scheme, these remain narrowly focused schemes. There remains a very significant policy gap following the closure of the non-domestic RHI that must be addressed if sufficient demand reduction is to be met.
- Enabling continued evolution of time of use tariffs within the retail market.
- Ensuring country wide connectivity, particularly rural broadband, to allow country wide participation in demand side response opportunities.
- Ensuring standardised and clear data capture and verification process for all demand side participants. This would include more standardised registration process, given that a significant proportion of homes that have solar or heat pumps have not registered with their relevant DNO.

The role of REMA should be to ensure that any positive market behaviours incentivised by dedicated demand reduction policies are also rewarded by the market. This will ensure that the benefits of demand reduction are recognised by all energy system users in the prices they pay for energy and the services they provide to the grid (including flexibility and demand side response).

As such, while agreeing that demand reduction doesn't need to be the focus of REMA, there must be clear joined up policy development between departments and policy teams. It is essential that the delivery of REMA, or development of any wider policies, does not have unintended consequences of undermining or becoming a barrier to each other. Part of the Governments respond to REMA should be laying out the governance arrangements being put in place to ensure joined up thinking between these policy areas, describing how different government teams are working together and avoiding the dangers of siloed policy making.

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 largely agree that the consultation identifies the key challenges for the future of the CfD. Principally that in its current form there is little incentive for a CfD asset to engage with wider market signals when only rewarding volume of generation.

We would also stress a longer-term challenge that the current CfD design runs the risk of placing greater pressure on the capacity market to provide security of supply if increasing volumes of generation are just supported to produce renewable power from variable generation, despite wider market signals. This could have the damaging impact of depressing the CfD strike price in the long run (if the value of the generation is lost) and making it no longer effective at delivering new renewable projects. This could become a serious barrier to renewable deployment.

To combat these issues, in 2023, the REA published our REMA report and analysis. Within this we argued that the wholesale market must be evolved to better reward key characteristics including flexibility, contract firmness, transparent market signals and better alignment between the different energy markets (such as the wholesale market, CfD, capacity market and reserve/balancing market). We also argued that such generation could receive a Green Premium.

Flexibility and Contract firmness (which reward projects for being able to guarantee a specified quantity of electricity or energy supply at a fixed price for a defined period) are seen as critical characteristics that need to be rewarded in future CfD designs if the contract is to remain valuable in the longer term. This would mean that a generator taking a CfD is then able to receive additional premiums, such as for green generation or opting for firmness. [For more information see the REA REMA Report: https://www.r-e-a.net/resources/rea-rema-report/]

However, in the short to medium term, we also stress that there is distinct value to being able to offer traditional CfD arrangements in parallel to more advanced contractual arrangements being considered and developed by REMA. Government should recognise that many of the identified risks are most keenly associated with variable renewable generation, such as solar and wind. All the proposals in REMA will impact different forms of generation technologies in different ways and will require careful assessment. For example, the ability to deem solar generation is likely to be easier than it is to deem offshore wind generation. It will take time for the impacts of new contract arrangements to be made clear and for more innovative contract designs to be offered to the whole market.

Equally, we also emphasis that government should not only be focused on creating contracts for variable renewables but recognise the need for low carbon firm and dispatchable capacity. This is currently delivered in the CfD by technologies like biomass, energy from waste with CHP (including advanced thermal technologies), tidal, hydro and deep geothermal. Such generation is also going to be needed in a secure and affordable energy system. The associated risks, and how they are shared between developer, investors, consumers and government are going to be differ by generation asset. The dynamic of risks for different sorts of generation therefore needs to be considered and the contractual solutions to these risks need to be appropriate and relevant.

Given the suggested complexity of offering new contract arrangements, which are needed, while also valuing the need to ensure there is no hiatus in investment and development of a range of generation technologies, we suggest that there will be value in both offering new CfD contracts (whether deemed or capacity payment) in parallel to offering traditional CfD arrangements in the short to medium term.

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?

While supportive of developments for a deemed CfD or capacity payment, we note that with the current level of detail in the consultation it is not yet possible to say how different forms of generation assets will respond. While we support the fact that a deemed CfD could potentially provide the opportunity for generation to be exposed to wider market signals, there is little detail as to what obligation or advantage there would be for assets to respond beyond just receiving the respective deemed or capacity payments for the generation. For example, where variable generation has zero marginal cost, it is not yet clear why they would then switch off under a deemed scenario. It is possible that development of such CfD contracts will need to be accompanied by further market rules (such as within the balancing market) which would ensure a response to wider market signals. Such rules have not yet been explored within the REMA consultation and will need to be developed in conjunction to new CfD offerings.

As identified in question 4, it will also be important to consider how different types of generation assets will respond to different forms of contracts. It could be more complex to deem certain forms of generation, while the benefits of deeming may be less explicit for generators providing firm capacity. As such, it will be a case of considering different generation assets to understand if the additional complexity of an evolved CfD will lead to significant behavioural change in practice. Overall further modelling, against different forms of generation, is needed to properly asses this question.

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)?

Offering an evolved CfD in parallel to a traditional CfD will provide both certainty and reward the market behaviours that need to be seen in a more decentralised energy market.

We welcome the proposed approach of evolving the CfD over time, providing ongoing reforms. However, changes need to be transparent, and where possible, optional. The CfD is already a well understood mechanism, which generators and financers already trust. It is delivering significant levels of capacity and works particularly well for fulled low carbon firm or dispatchable generation. It, therefore, is the right mechanism for helping to scale investment and already distributes risk well in the immediate term.

However, we also agree that evolution of the CfD is needed in parallel to the traditional CfD. As identified, offering a deemed or capacity payment CfD would enable generators to be more responsive to market signals and received advantages for doing so. We, therefore, believe that having an intial option to bid for either a deemed or traditional CfD will also help to establish the advantages of the deemed market for generators and reward desirable characteristics that government are looking to support within the market. Overtime, the traditional CfD could then be phased out of the auctions, likely within the 2030s.

We agree with Government that over time such reform is required, otherwise meeting security of supply requirements, as larger volumes of variable renewables are connected, will increasingly place pressure on the capacity market and risk the devaluation of the CfD strike price over time.

Scaling investment also requires clear timetabled auctions with dedicated budgets on a three-year rolling horizon.

To scale investment, the administration of the CfD must also become more transparent and predictable. It is positive that Government have now moved to annual auctions, however the actual timings of auctions and allocated budget is only visible a couple of months in advance of the auction. This does not help developers plan a pipeline of projects and provides little certainty over the likelihood of success once bidding begins. There should a clear timeline for future auctions, on a three-year rolling horizon basis, with clear committed budgets put in place well in advance. This should be aligned to the delivery of the Governments 2035 net zero power grid target. This transparency will help developers and financers plan, while also insuring applicates are more prepared for the auctions.

REMA must also consider how existing generation capacity is to be maintained as projects come to the end of their Renewable Obligation

In addition to scaling investment, REMA should also be considering the importance of maintaining existing generation. From 2027, contract arrangements for existing generation will start come to the end as the first few projects come of their Renewable Obligation contracts. REMA should make clear the intended market arrangements for ensuring this existing capacity is maintained. Options such as repowering CfD's or bridging mechanism need to be made explicit for the whole market, otherwise further Government money will be wasted having to replace existing low carbon capacity. Market arrangements must avoid this, and the proposed arrangements made clear as soon as possible to provide confidence to the market.

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.

Deeming arrangement should be kept as administratively light as possible, to avoid additional cost being added to generation facilities. As such either option 2 (where asset owners conduct their own data collection and calculation) or Option 3 (where government appoints reference generators) are likely to be the most workable.

We, however, note that none of these really address the main gaming issue, which is ensuring that generation is incentivised to respond to wider market signals. If generation has zero marginal costs of operation and they are guaranteed a payment through deeming, then wider market signals themselves may not be attractive enough to incentivise responsive behaviours. Wider market rules, such as within the balancing market, may need to be considered to make a requisite of responsiveness for deemed CfD generation. In doing so this physically restrains the options for gaming and ensures delivery of the market outcomes being pursued by the development of a deemed CfD.

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.

It is likely that a capacity- based CfD will increase strike price bids, without a clear advantage to why paying for MW capacity is likely to be better the paying for the MWh of generation in the current CfD. We note that it will be very difficult for a generator to effectively model anticipated revenues from other markets, especially initially. As such, investors will want to see a larger proportion of their revenue covered by the capacity payment and will see a gain share mechanism as an additional cost that could impact the project.

Equally, we understand why Government would also want to accompany such a payment with an availability factor, however this could undermine the market signals that REMA is trying to get generators to respond to. Generators may choose to be consistently generating to not be penalised by the availability factor. As such we do not believe this model would be as effective as a deemed CfD in meeting the REMA objectives.

9. Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q5 on which actors are best placed to manage the different risks?

The offering of a deemed CfD in parallel to a traditional CfD, for the next few CfD allocation rounds until the deemed market is established, would deliver an appropriate risk distribution across developers, investors, consumers and government.

In terms of defined capacity, if this is set at the maximum possible capacity for one hour per year, this may cause unintended behaviours such as at wind farms with low efficiency but very high cutoff frequency, or solar PV sites with on-site storage but no ability to export the max, due to grid constraint. Hence in these circumstances one could argue that almost certainly, de-rating would need to be applied. This effectively converts the CpCFD to a deemed CfD.

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.

With the current evidence base and considerations within the consultation, the REA currently favour a deemed CfD . This both helps to derisk revenue, while also allowing for there to be opportunities to respond to wider market signals without the need for an availability factor or gain share mechanism which create added complications that may deter investors.

As expressed above, we think the introduction of the deemed CfD needs to be done in parallel to offering a traditional CfD. Given that it will be easier to deem some forms of generation then others (for example easier to deem solar then wind) it may be appropriate for government to think about a staged phasing in of deemed CfD offers, in successive allocation rounds, in order to establish the market. Market behaviours to these CfD options can then be considered.

We also note that it remains difficult to properly consider the full impacts of the proposed interventions while REMA continues to have a wide number of proposals on the table. For example, it is not yet at all clear how location pricing (such as zonal pricing) will operate in conjunction with deemed CfDs. While possible for both to work together, deemed CfDs could themselves be used to reduce the cost and impact of grid constraints, reducing the need and impact of locational pricing. As such, there remains too may possible interactions and uncertainties in relation to the variety of REMA proposals to make a definitive assessment of the CfD possibilities. As such, it is important that following this consultation, government work to urgently refine the options, and come back to industry with more concrete proposals.

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

It is difficult to give a definitive response to proposals for a partial CfD given the range of options being considered by REMA. We do see some potential merit in a partial CfD, as it provides an option for the generation outside of the CfD to be specifically rewarded for being green, however more detail is really needed. We believe the proposals would need to be accompanied by developments in the CPPA market), with an additional Green Premium provided (see question 1. Without this the remaining generation would likely be traded at a heavy discount and not be attractive to investors.

Given this, we believe the consultation is right to note that such a payment structure could significantly increases the generators risk, and likely to result in higher strike prices for less generation. As a result, the percentage of generation that falls withing the CfD will likely need to be high, with only a small percentage (~10%) left outside of the payment.

Unless well designed the impact of a partial CfD could be limited, adding additional complexity for little gain.

We note that there could possibly be a specific role for a partial CfD in helping to repower sites and ensure existing generation, which is coming to the end of their renewable obligation contracts are kept operational. With the capex for building the sites having already been spent, a partial CfD could help finance refurbishment of existing generation, while leaving most of the plant merchant and able to respond to wider market signals. To an extent, this is what is happening today where sites are adding unsupported capacity to existing CfD supported sites.

For the above reasons, we think a partial CfD should continue to be considered, but with clear focus on what parallel reforms maybe needed to the CPPA market and whether its use should be focused at particular circumstances in the market (such as repowering). In such a scenario, it would complement, not replace, proposals for a deemed CfD.

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.

We are supportive of continuing to consider reforms to the reference price. Within our REMA report, published in 2023, we highlight that gradual extension of the market reference price horizon has the effect of firming up the non-firm CfD and increasing its value. It also provides more granularity and helps create a market signal in a longer horizon which gives the market time to respond. This enables wider participation of flexibility.

A key timeframe for flexibility harnessing is 72 hours. This captures the bulk of domestic flexibility in terms of import from the grid, in particular for heating and electric vehicle charging. To harness this flexibility, it is important for the wholesale market to be deep and liquid at half hourly resolution. Then consumer equipment can be programmed to optimise import from the grid according to user parameters such as energy use within the 72-hour period, charging status at the horizon, and reward related discretion on end use (temperature in the comfort range above the health threshold, duration of temperature, number of rooms heated, travel etc.).

For further evidence to consider on extension of the reference price, see pages 20 – 21 of the REA REMA report here: https://www.r-e-a.net/resources/rea-rema-report/

However, we stress that any reform to the market reference price must ensure that it is transparent to developers and allow them the ability to model market interactions. If changes to reference price increase the complexity, making it difficult to be certain of revenue returns then this will reduce investor confidence in the CfD, undermining the objective of increasing the scale up of investment in generation. We believe this could be a significant risk if looking at a hybrid reference price, which is likely to create a level of uncertainty and complexity which may undermine any gains that are provided in terms of encouraging hedging.

We would urge that government make an early decision on the reference price as this will help industry to properly consider wider REMA reforms like the deemed CfD and locational pricing.

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?

Current REMA proposals do little to support the deployment of smaller scale renewable projects. Given the pre application requirements and administrative burden of applying, we suspect that that generation below 5MW threshold will remain unlikely to find the CfD attractive, unless there is a significant redesign to the application process (which we would support). However, in the absence of such a redesign, we believe Government should explore the option of allowing group applications with multiple sites in one bid, where the combined capacity is above the 5MW threshold. This could see delivery of range of smaller projects, without significant added complexity to the auction or budget. This also provides benefits of scale that reduces the administrative burden for smaller sites entering the CfD, where it will be managed by one umbrella applicant.

We would also support continued reform to the Smart Export Guarantee, where tariffs for onsite generated power should better reflect prices for wholesale generation, as well as provide significant rewards for domestic and commercial flexibility services.

The PPA market will also continue to have a role in delivering smaller scale generation, and it will be important that PPA's are made to work with REMA reforms, such as enabling a PPA with a deemed CfDs or capacity market contract. However, we reiterate, that the biggest barriers to smaller scale generation and the PPA market remain the physical market barriers and accurate data management. This includes urgently addressing grid capacity constraints at the distribution level and speeding up the planning process. This should also include addressing known leasing barriers to the build out of rooftop generation, especially on warehouses, where more standardised commercial rooftop agreements could support the sector.

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 REA are supportive of seeing the introduction of a minima with the capacity market and agree with the conclusion that this provides both administrative simplicity and flexibility rather than having two separate auctions. However, there is little discussion within the consultation around the different characteristics that government would look to support through the minima. It is essential that these characteristics are closely aligned with the government 2035 net zero power grid target. ***As such minima cannot be used to support the build out of new fossil generation in the capacity market, including unabated gas.*** It is likely that such a minima will be ineffective in providing value for money if it results in building stranded unabated gas assets that means the government misses both its decarbonisation and energy security targets.

The minima should be based around both clear flexibility signals and low carbon emissions. This will support the build out of low carbon generation and clean technology storage solutions, which will need to be the prevalent forms of secure capacity within a fully decarbonised power system. This includes a range of storage technologies, including (but not limited to) battery storage, liquid air storage, pumped hydro, hydrogen, green gas or low carbon firm power generation including bioenergy with carbon capture and storage. It is these forms technology that should be the focus of a minima rather than new unabated gas generation.

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?

Further factors relating to the CM Framework and parameters that should be considered include:

- Commissioning dates and contract lengths within the capacity market are currently aligned with fossil generation lead times. Contracts provided by the Capacity market should offer longer term commissioning dates, aligned to realistic renewable energy and clean technology build times that provide longer term contracts more suited to developing new low carbon assets.
- Extend proposed 3-year agreements to low carbon refurbs. This 3-year agreement could be used to extend the lifespan of a low-carbon asset where the main capex has already been invested several years before the auction. It is recognised that appropriate eligibility criteria would need to be developed to ensure further investment is focused on decarbonisation activities and it is helping to meet the shortfall in capacity.
- Enable CfD projects to also bid into, and benefit from, the capacity market to encourage flexibility. With a deemed CfD it could be possible design a capacity market contract that rewards available capacity, without double subsiding the generation. This would encourage colocation of CfD projects with storage assets that could feed into the capacity market. Failing this there needs to be clear pathways allowing projects to switch from CfD to capacity market contracts if its suitable and commercially attractive for them to do so.
- Ensure that battery degradation issues with EPT testing are resolved to better facilitate their inclusion in the capacity market. This includes recognising improved technologies and applying increasing derating factors that are aligned to degradation over time. This will also need to be accompanied by permitted augmentation within storage contracts so that batteries can be replaced within the contract lifetime as they degrade.
- Ratcheting down the emissions Limit. Overtime the capacity market should be ensuring that contracted generation is decarbonising. While the existing threshold should be tougher and kept under review. It could also be used to send a stronger market signal if there was a clear trajectory for the emissions limit to decrease.
- Clarify the interaction between capacity market contracts and other government support mechanisms including Low Carbon Hydrogen Production Business Model and the Power BECCS, Industrial Carbon Contracts and Greenhouse Gas removal business models.

- Delivery of the capacity market should also be aware of existing capacity assets coming to the end of their contract arrangements from 2027 onwards, under the RO, as well as in the future under CfD arrangements. It is important that such assets can enter CM auctions, with the ability to secure CM contracts for when existing arrangements end. This could prove crucial to maintaining low carbon capacity and contributing to the decarbonisation of the capacity market.

Regarding the Capacity Market Auction Design, the REA explored several options within our 2023 REMA report. This includes:

- Have more frequent CfD and Capacity market auctions, with a clear timetable for allocation rounds with a three-year rolling horizon and stipulated budgets.
- Providing a firmness option within the capacity market contracts. This goes beyond just responding to moments of stress to deliver energy security, but actively rewarding generators for being able to produce energy at specific times, specific durations, and specific volumes, at expected high demand periods.
- Harmonise the capacity mechanism with its adjacent markets so that the same service gets the same price at the joins. The key adjacent markets for storage are reserve and balancing.
- Provide a scarcity uplift to a CM reference price when the market is within designated regimes of scarcity.
- Develop a deficiency mechanism and secondary markets, enabling non punitive non delivery if declared early and in addition enabling offering of overlapping services.

For further detail on the above read the full report here: https://www.r-e-a.net/resources/rea-rema-report/

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?

Yes, the REA agree that lower emission limits for new build and refurbishing CMUs should be introduced as soon as possible. We argue that there should be a ratcheting down of the emissions limit overtime. The capacity market should be ensuring generation that is contracted is decarbonising. It could also be used to send a stronger market signal if there was a clear trajectory for the emissions limit to decrease.

However, we are also clear that delivery of these emission limits will be dependent on Government delivery of policy support for carbon capture and storage contracts that remain aligned with capacity market emission ambitions. To date the continuing delays to the delivery of the power BECCS and GGR business models, as well as sequencing allocation rounds, means that it may not prove physically possible for CMUs to meet decreasing emission limits from 2026. This must be avoided. Joined up policy making is urgently needed to ensure that decarbonising solutions are progressed by wider government policy so that a decarbonised capacity market can be realised.

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?

We believe that with aligned policy developmnet, emission limits within the capacity market will see investors focus on clean energy solutions including co-located energy storage and bioenergy carbon capture and storage solutions. However, a s a trade body who are not directly involved in investing in flexible capacity, we leave our members and wider stakeholders to answer this question directly.

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?

We are supportive of the polices that are listed and believe they will help in seeing unabated gas plants decarbonise. However, we warn that many of the listed polices are seeing significant delays and their progress remains too slow to see sufficient progress. This includes the fact that:

- GGR and Power BECCS Carbon capture business models are still to be finalised and the sequencing process for allocation remains too slow.
- Capacity Market reform was consulted on in 2023, but Government is yet to publish their immediate next steps.
- We are yet to see the results of the H2P and Power CCUS consultation in terms of their involvement in the capacity market.
- Establishment of a 9-year Capex threshold was first consulted on in 2022 and is still not implemented, nor are wider capacity market changes.
- Decarbonisation readiness requirements were consulted on in March 2023. More than a year on, and industry are still awaiting a response.

The industry is concerned by the slow progress policies are currently making and are weary that further delays are expected given we are in an election year. Confidence must be given to the sector that these policies will be advanced as a matter of urgency.

Given the above, we also stress that the Capacity Market should not be looking to contract new unabated gas generation. We are beyond the point that such technologies will be able to decarbonise in sufficient time to meet the Government 2035 net zero power system target. This is exacerbated by ongoing delays, as listed above.

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.

No, as described in question 18 we do not believe that unabated gas generation is likely to have the time or investor confidence to later decarbonise, and that their use does not align with the Government net zero power system target for 2035. Such generation should not have any ongoing contracts after 2035. Support of new unabated gas generation today is very likely to result in stranded assets being both a waste of capacity market budget and leading to more expensive decarbonisation actions in the future.

Instead, the capacity market should be focused on the delivery of renewable generation, including baseload capacity like bioenergy with carbon capture and storage, and the wide range of storage technologies, including hydrogen.

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.

We agree that there is a significant number of workstreams underway that will help the delivery of distributed low carbon flexibility. We also welcome the fact that these are well reviewed in Appendix 3, which we hope will also encourage greater joined up thinking regarding how these separate policies are delivered together. The REMA team should play an ongoing role in both monitoring the progress of these polices, ensuring any additional delays are avoided and ensuring joined up policy making.

We also stress that delivery of these workstreams need to be accompanied by critical moves to remove the physical barriers to the deployment low carbon flexible generation. This includes addressing grid capacity constraints and speeding up planning processes. Failure to address these fundamental barriers will undermine any work that is done to address market signals and behaviours. If the generation cannot be built and connected, then it will not be there to participate in the market.

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.

The REA strongly support the use of additional bespoke mechanisms to see the establishment of nascent sectors including those of long duration energy storage, low carbon hydrogen production and carbon capture and storage. These mechanisms need to be established as a matter of urgency so that they can mature and then be able to respond to sharper market signals and an optimised capacity market. Failure to prioritise their delivery will make REMA market reforms less successful and delay delivery of overall decarbonisation ambitions. A key commitment from this second REMA consultation should be to prioritise delivery of these bespoke mechanism to get those market going while further capacity market and CfD reforms are introduced.

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 recognise and agree with the key design choices being considered in the design of zonal pricing. We are pleased to see that treatment of existing generation is being closely analysed. This is essential as such projects are very unlikely to have practical way to relocate with the introduction to zonal pricing. If the introduction of locational pricing was to undermine existing asset value it will cause very significant damage to investor confidence and damage future scaling up of investment, a key objective of REMA.

We also welcome the focus on the impact to the consumer. We note that there can be significant changes to the modelled cost of capital of new generation depending on the assumptions used. If done badly the cost advantages of zonal pricing could quickly be lost and consumer negatively impacted. A threshold for worthwhile consumer benefit should be made clear and stuck to in terms of the decision making around zonal pricing.

In terms of missing design considerations, we would also stress that a close anlysis of how physical grid capacity constraints could undermine any locational signal needs to be conducted. While modelling may suggest changes in generation location, if it proves impossible to physically connect in such areas then it might well be that a move to zonal pricing is unable to make a significant difference. Zonal pricing is only worth doing if generation is enabled to physically respond. Failure to do so would make the exercise redundant.

Analysis of what the introduction of zonal pricing could mean for the PPA market is also required. If the move to zonal pricing is not transparent and zonal pricing creates uncertainty it will make it very difficult for business to enter a corporate PPA arrangements. This could slow investment and deployment of renewable generation. It is essential that any decision to move to locational pricing is accompanied by clarity on how prices of each area can be modelled so that PPA modelling can be conducted.

Design choices should also be assessed for political risk. Delivery of locational pricing will need public support and strong communication as to what advantages there are to seeing different prices across the country. Failure to get broad political and public consensus could see the delivery of locational pricing, if committed to, become derailed and slowed. The ability to ensure that any final decision on locational pricing can actually be delivered politically needs to be considered.

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.

The REA are supportive of the continued analysis of alternatives to locational pricing and believe they are more likely going to be easier and quicker to introduce.

We particularly support further consideration around grid charging reforms and expanding measures for constraint management including evolution of the constraint product market. This has the potential to reward both existing and new renewable assets, while still creating an element of location-based advantage. We would be happy to support further efforts in modelling how such arrangements could better provide locational signals. We also recognise that this could be delivered in conjunction with some form of zonal pricing if done carefully and transparently.

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 proposed steps being taken but note that it is difficult to make significant comment on the proposals until National Grid ESO have completed their work on modelling dispatch and scheduling arrangements. It is essential that NG ESO engage with a wide variety of generators and stakeholders as they carry out this analysis and the REA are already helping them talk with relevant generators. We look forward to further engaging in this workstream.

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?

The REA believe that for the most part appropriate risks are already well allocated across market actors within the existing CfD and capacity market arrangements. We recognise that it could be appropriate for generators and investors to take on additional risk through the introduction of some form of locational price signal. However, we stress, that it would only be appropriate for this risk to be applied if locational price signals are transparent from the start and can be appropriately modelled. Introduction of locational signals without significant clarity and forecasts will create to greater uncertainty for investors and risks creating a significant investment hiatus. This must be avoided.

In addition, we note that weather risk is not efficiently placed with the generator, the system operator who has view of the whole system is better placed to deal with this. By contrast operational can largely fall on operators who are managing the site and are able to react.

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

While the REA recognise and agree with the anlysis of the remaining options, we stress that there still remains a significant number of proposals on the table. As such it is very difficult to properly consider all the interactions and possible outcomes, especially in the limited time provided for responding to this consultation.

Further refining of options is really needed before industry can be clear on how things like a deemed CfD would interact with locational pricing, or how a generator would view the reformed capacity market compared to a PPA. It is important that Government set out clear timescale for future decisions on REMA, including committing to taking further options of the table by the end of 2024 so that final decisions can be made some point in 2025. Accelerated anlysis and more regular industry engagement is needed to fully explore these interactions and come to appropriate conclusions.

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

We note that the anlysis so far of the evidence in the consultation on legacy arrangements is limited and made more difficult by the number of proposals still being considered within REMA. There remain far too many unknowns for existing generators to have confidence that REMA decision will not have a negative impact on their existing assets. As such, while we appreciate the proposed approach, we emphasise the importance of speeding up this analysis and that full engagement with existing operators is needed in 2024 if Government are serious about coming to realistic conclusion in 2025. A timetable for this engagement should be published as part of the government response to this consultation.

More evidence and transparency are needed, along with clear statements of intent that Government do not want to undermine existing business models through decisions made with REMA. This should include strong statements about grandfathering specific arrangements as part of the REMA process. Failure to do so will damage both investor and developer confidence further. This could undermine REMAs overall objective of increasing investment in the deployment of new renewable generation.

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

The biggest risk to legacy arrangements is that final decisions within REMA have the potential to devalue existing projects. For example, considerations of locational pricing are already causing concern for asset owners that the value of their existing assets could be undermined due to where they have already built, with little way to address this risk.

While it is appreciated that the consultation already considers the impact on CfD assets, it needs to be recognised that the majority of low carbon generation continues to be operating under the Renewable Obligation and will be into the 2030s. The current consultation provides little confidence to such generators apart from highlighting that the RO will be further considered in the next phase of REMA. The timing for this consideration is critical. Existing generators are starting to come to the end of RO arrangements from 2027 onwards. They are already considering options for either repowering or decommissioning assets. With out clarity for how REMA decision will impact them, or the government's position on keeping assets operational, it makes it much harder for them to commit to continuing to maintain this capacity. In the long run this will mean that low carbon capacity could be lost and will need to be replaced at a higher cost then just maintaining it now. Decision on how RO generation projects are to be treated at the end of their contracts and within REMA decisions are needed urgently in 2024.

We also note that government should be aware of the impact not only to legacy assets but also on projects that have already reached financial close but are not yet built. While already built assets may be able to adjust for different revenue assumptions, agreed pipeline assets are more likely just to be abandoned if the market assumptions against which they were agreed are changed. This could see already committed investors leaving the UK market. As such not only does government need to consider built legacy arrangements, but also committed pipeline projects.

Early government commitments to how both existing and pipeline assets will be protected from negative impacts of changes in the market need to be made as soon as possible to continue reassure developers and investors that changes outside of their control will not undermine their business model.

REA, May 2024