BEIS Consultation on the Review of Electricity Market Arrangements (REMA) – REA Response

The Association for Renewable Energy & Clean Technology (REA) is pleased to submit this response. The REA represents renewable electricity, heat and transport, as well as Electric Vehicle charging infrastructure, Energy Storage and Circular Economy companies. Members encompass 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 around 550 corporate members of the REA, making it the largest renewable energy and clean technology trade association in the UK.

Response Contents

Introduction

Our core objectives for REMA:

- Delivering a Net Zero power system by 2035 at the latest - but we believe this can and must happen by 2032 - and enabling consumers to reap the benefits of affordable renewables, should be the guiding aims for the REMA process.
- Delivering a flexible power system with security of supply will be key to consumer confidence in our energy system and crucial to Net Zero.
- Government must consider what the best options are for delivering a Net Zero power system by 2032 or earlier in a timely fashion and prioritise further exploration of these options, so long as they can meet other important objectives. We are particularly keen to see the delivery of reforms for flexibility, wholesale market reform and low carbon power.
- We consider locational pricing and operability reforms to be lower priority for delivery, though stress that they remain important considerations to the overall vision.
- REMA must also dovetail to urgent energy crisis-related and longer-term system reforms also being progressed across the energy market – a document setting out all the various strands of current reforms and how REMA relates to these would be a helpful starting point for this.

Please contact Mark Sommerfeld (Head of Power and Flexibility) and Callum Coleman (Policy Analyst, Power & Flexibility), to discuss the content of this response further.

Chapter 1 – Context, Vision and objectives for electricity market design

1. Do you agree with the vision for the electricity system we have presented?

Net Zero by 2032

We welcome the focus on expediting low carbon technologies and driving flexibility in REMA, however, stress that reforms must include a diverse range of renewable generation and clean technologies to see the delivery of a fully decarbonised power system.

We know that power demand is likely to double in line with the electrification of heat and transport, and a move away from fossil fuels. At the same time, REMA outlines the need to focus on the cheapest forms of generation, which are renewable, and deliver a flexible decarbonised system. As such, we do broadly agree with the principles behind the 'vision', although encourage government to be as ambitious as possible with its decarbonisation targets, ensuring the right levels of investment and due attention from Government. The 2021 REA Strategy suggested that a fully decarbonised power system, with the right support, could be delivered as early as 2032, three years before the Governments own target.

Delivering Energy Security and an Affordable Energy System for All

The REA is clear that not only should the reforms envisaged in REMA deliver decarbonisation, but cheaper bills, and that market mechanisms insulate consumers from volatile wholesale energy prices. Particularly in context of the current energy crisis, which has highlighted the need for future-proof markets operating in a Net Zero electricity system, and security of supply. As such, we welcome the ambition displayed in REMA, however, raise the point that REMA does not sufficiently consider consumer and market realities.

REMA assumes that smart metering, heat and transport electrification and energy efficiency are being taken up widely across the population. The reality is that all of these areas are far behind where they need to be on consumer uptake, and because of this, vulnerable consumers in particular may not be able to access or participate in the flexibility services that REMA assumes. Such consumers, especially the 4 million consumers living with pre-payment meters, will not be able to participate. REA has previously issued calls for an energy efficiency installation programme that could begin to address some of these inequalities. Reforms under REMA should be designed carefully to ensure that such consumers (generally earning lower than average salaries) are not further penalised through higher bills compared to the existing system and should help to incentivise consumers to offer greater flexibility to the electricity grid system.

2. Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost-effectiveness)?

Our position

REA believes that decarbonisation should be the top priority of the three objectives, though we agree that all three of these interlinked objectives are key for electricity market reform.

We welcome the Government's recognition that delivery of decarbonisation, security of supply and cost effectiveness are complimentary in market design, rather than separate objectives working against each other, as it was once termed in the old 'trilemma'.

We are keen to see recognition that the future electricity market must attract continued investment, and we are concerned that the Government may take a short-sighted view of cost-effectiveness. We would also like to see even greater ambition – the Government and industry should aim for a Net Zero grid by 2032.

If the Government focuses on decarbonisation as the main priority, electricity prices will ultimately fall to lower levels, and this will achieve a more cost-effective and independent electricity system over time.

It will be important for government to prioritise reforms and consider their delivery over a range of timescales. While intervention in the immediate term will be needed to bring down the cost of energy bills to consumers, government must simultaneously be looking to the medium and longer term where well-thought through market reform is required to decouple the marginal cost of generation, set by internationally-traded fossil gas, and better reflect the lower generation costs of renewables. Equally this must also lead to a rapid acceleration in the deployment of a wide range of renewables and clean technologies delivering affordable domestic generation, energy security and decarbonisation. In addition Government must also continue to focus on supporting less developed zero and low carbon technologies and First Of A Kind (FOAK) systems, and make rapid and significant investments in our physical network infrastructure so that it is fit to meet the needs to a fully decarbonised and flexible energy system

Chapter 2 – The case for change

3. **Do you agree with the future challenges for the electricity system we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges.**

Additional challenges

REMA identifies some of the future challenges for the decarbonised electricity system, however there are several further challenges that we would like to see acknowledged in the response to REMA and in future consultations on this area:

The Government does not appear to recognise the scale of the physical network infrastructure challenge in REMA. Grid capacity constraints at both the transmission and distribution level, leading to connection agreement lead times of up to eight years, remains the single largest barrier to delivering the levels of renewables, flexibility and grid operability required. REMA is focused on helpful market reforms but ignores the very real physical grid constraints that are stopping development and undermining market signals. Although National Grid recently announced a £54 billion investment in network infrastructure, some estimates suggest this falls short of what is needed. The Government's Electricity Networks Strategic Framework suggests that the physical network infrastructure requires £40-110 billion of investment.[1] Ofgem also recently confirmed a £20 billion investment in the energy transition, but this is not all allocated for network infrastructure.

We also need to explore alternative options to overhead power line upgrades and new lines, to minimise local impacts and possible public opposition. These include more flexibility assets to provide alternatives. *We need the Government to recognise that a wide range of renewable energy and clean technologies will be required to effectively meet demand*. This will ensure provision of a stable and secure supply. Future demand will be met not only by solar and wind power, at all scales, but by a wide range of technologies including bioenergy, marine power, hydro power, geothermal, net zero hydrogen along with energy storage of multiple durations, and other innovative technologies. Delivering this mix of technologies will require substantial investment in innovation and strategic direction between Government, the FSO, National Grid ESO, Ofgem and key industry bodies.

We would also like to see greater recognition that there is a strategic direction and coordination challenge. With so much reform happening across the energy sector alongside decarbonisation reforms in the construction and industrial production sectors, we need to see a much more joined up, informed and strategic approach from Government and involved bodies. An ongoing and future challenge to delivering a Net Zero electricity system by 2035 is ensuring strategic direction and a coordinated relationship between Ofgem, National Grid ESO as the Future System operator (FSO), BEIS, the ENA, electricity code administrators and other key industry bodies. It is, therefore, essential that REMA considers and makes clear the independent role that the Future System Operator (FSO) will have in also delivering the reforms considered in this consultation. A key output of REMA should be a mapping of all workstreams currently relating to grid systems currently taking place. This will create a useful and transparent base from which the FSO could start to coordinate its activities.

It must also be recognised that diversity of generation and clean technologies is going to be crucial to delivery of a stable and secure energy system. Our future power system must be flexible and resilient, utilising both variable and firm renewable generation, along with storage, to ensure reliable supply to meet future demand.

The challenges set out in REMA also do not make reference to the increasing demand from electrification of heat and transport, and how this is a variable factor under different delivery scenarios for electrification of heat and transport and the uptake of energy efficiency measures. At present, with progress in these areas having been slow, there is a risk that the required delivery of decarbonisation in these areas will have to happen much more rapidly than otherwise, and this would be a substantial shock for the electricity system to have to adapt to.

[1] Department for Business, Energy, Industrial Strategy and Ofgem. "Electricity Networks Strategic Framework." 4.08.2022

4. . **Do you agree with our assessment of current market arrangements/ that current market arrangements are not fit for purpose for delivering our 2035 objectives?**

The current market arrangements are not fit for purpose for a Net Zero electricity system by 2035

REA agrees that the current market arrangements are not fit for purpose for a Net Zero electricity system by 2035 without significant reform, and strongly welcomes the Government's decision to explore this necessity through REMA. All reforms, though, must be mindful of maintaining investor and developer confidence. Some areas, such as flexibility, will require extensive policy developments and new mechanisms, while others (for instance, Contracts for Difference) will require a lighter approach to reform. Additional funding and tax reform is also required to support new technologies and energy efficiency improvements. All reforms will also need to be done in conjunction with considering the government's progress in the retail market review.

The balance between speed of delivery and careful transition planning

While we appreciate that at this early stage of consultation, we highlight that 2035 is only a little over 12 years ahead of us. With a consultation process on the specifics of market reforms likely to take us well into 2023, and a carefully thought-out transition period required for many of the reforms, we must see a clearer vision from BEIS on the timetable of consultation processes for the reforms and the timeframe for transition periods.

The importance and urgency of the challenge is underlined by the current energy price crisis, and we would hope to have reached a long-term solution to the wholesale market price issues by the start of the next heating season – October 2023.

We hope that BEIS will carefully consider the responses to this consultation, and then, set out its intentions to industry in appropriate time, given the short-time frame in which we now have to achieve the UK's 2035 Net Zero power system target. We would also like to see clear delivery objectives and interim milestones for how the UK's power system will reach Net Zero in the years leading up to 2035.

Security of supply and fossil fuel energy markets

The current electricity system does not adequately deliver security of supply. We recognise the achievements to date made towards the Net Zero 2035 goal through vital schemes such as the Renewable Obligations scheme and Contracts for Difference but argue that realising a Net Zero carbon power system by 2035 will require a fundamental step away from the inherently volatile global fossil fuel energy markets and a shift towards greater security of supply.

Chapter 3 – Our approach

5. **Are least cost, deliverability, investor-cost, whole-system flexibility and adaptability the right criteria against which to assess options?**

Consideration of 'least cost' must recognise the returns on investment to be delivered, while alignment with a Net Zero power system by 2035 – and the need to focus on the 2050 target - should also be key criteria.

For the most part, we acknowledge that these are correct criteria against which to assess options, but would urge caution against being led by a short-term approach to least cost as the key criterion. It is important to be mindful that least cost today, may not prove to deliver the least cost for consumers in the future if it does not deliver a fully resilient and decarbonised energy system. The costs of the reforms being introduced must be considered investments that deliver very real returns for the country, in both social and economic terms.

In addition, there should be two additional criteria. First, "alignment to delivering the UK's commitment to a Net Zero electricity system by 2035 and Net Zero 2050". This is firstly to ensure that all steps taken as a result of REMA are in line with broader long-term decarbonisation goals. Second, the REA is concerned that solutions only targeting 2035 commitments may require substantial re-work, un-doing and replacement in order to achieve 2050 commitments. Moreover, projects built today could have a plant life to 2050, as such there could be significant risk of stranded assets if REMA is not 2050 aligned. We believe that REMA reforms should firmly have the 2050 target in mind as this approach will be more affordable, reliable and resilient in the long-term.

Second, there should be a criterion that commits to take a whole system view, with a focus on transmission and stability services. This is an area currently overlooked in many of the proposals brought forward and this criterion would help to amend that. This includes the interactions between the transmission and distribution grids as well the interaction of the power grids with the gas grid, a future hydrogen grid and the required large scale energy storage infrastructure. There needs to be clear and transparent processes of how all "grids" will operate and incentivise all participants (whether generation, demand side and "flextech" solutions) to deliver value-driven, reliable Net Zero services.

National Grid's Future Energy Scenarios (2022) includes a strong recommendation that '*Strategic coordination and whole system thinking, especially across the electricity and hydrogen sectors, is required to achieve decarbonisation targets and avoid unmanageable network constraints and potential curtailment'.*

6. Do you agree with our organisation of the options for reform?

While the options make a good start at grouping some of the issues, we would like to highlight a few comments and recommendations for adjustments below:

- *Many of the options are not mutually exclusive and may actually provide greater benefit when used together, alongside one or more other options*. We would like to encourage BEIS to undertake some analysis on how different options might interact with and complement one another.

- *None of the options directly address physical infrastructure issues*. Capacity constraint issues continue to be driven by underinvestment in the physical network infrastructure. Resolving these will be the most significant barrier to delivering mass low carbon power, flexibility and security of supply, and it is disappointing not to see any outline plan for incentivising upgrades of physical network infrastructure or direct commitment toward upgrading the network infrastructure from the Government. While we appreciate that locational pricing may be intended to incentivise delivery of some of the required investment, we have concerns that this could be a market-based solution to a physical network problem Consideration also needs to be given to upgrades and investment required on the gas grid and hydrogen storage, to enable the full decarbonisation of the electricity system. Hydrogen blending into the gas grid initially, and repurposing of the existing gas grid to 100% hydrogen where needed, will be required to enable energy to be carried across the country, from centres of supply to centres of demand, where this cannot be delivered via electrons. Whole system planning and careful consideration of the interaction between gas and electricity grid is vital to ensure existing infrastructure is used in an optimised way and new, targeted and more costly infrastructure is built only when essential. Location of electrolysers should also be considered as locating electrolysis in zones of constrained power transmission is considered a key solution for reducing the costs of constraints and new network reinforcement (Afry, 2022)[2].*The options do not sufficiently consider highly relevant topics beyond the scope of REMA such as energy efficiency, the uptake of smart meters and retail market reform.* We would like to see greater analysis of the interaction between the options set out in REMA and these other areas in the Government's response to the evidence provided.
- *Chapter 10 seems to be slightly abstract within the document and interaction with other Wholesale Market reform and Mass Low Carbon Power options is not sufficiently considered.*

7. What should we consider when constructing and assessing packages of options?

There are a number of crucial interactions and impacts that BEIS should be considering when constructing and assessing packages of options:

Retail market and vulnerable consumers

- Interaction with the retail market. This is particularly relevant in light of BEIS' stated intention to open consultation on retail market reform, and the current crisis of high consumer energy prices.
- Impact on vulnerable consumers, again particularly relevant in light of the current crisis of high consumer energy prices and forecasted recession.

[2] Benefits of Long Duration Electricity Storage, 2022. A report written by Afry for BEIS.

Investors

- Impact on investors and how to incentivise investors to rapidly deliver the required capacity of new zero and low-carbon generation and electricity storage to meet the Net Zero by 2035 target. In delivering reforms, it is essential that this also includes consideration of existing business models and revenues of already operating low carbon assets. Their commercial viability must be protected to ensure investor and developer confidence in maintained in the UK market.
- Further to this, BEIS need to consider how much of the market will be exposed to any changes. Existing generation is rightly likely to be protected or grandfathered, so may not fall under the new rules.

External requirements (decarbonisation of other sectors & security of supply)

- The ideal projected versus the real-time uptake of EVs, solar panels, heat pumps, battery storage, energy efficiency improvements and other energy saving materials at both the domestic and commercial scale
- Longer-term electricity demand forecasts and network upgrade requirements
- Security of supply (national energy independence in context of global political tensions and the increasing changing weather)

Timelines and data

- Timelines: there is a need to ensure that changes are introduced in an order that makes sense, with sufficient signposting, and appropriate urgency.
- This will need to include priority setting for reforms. Focusing on delivering wholesale market reform and the role out renewables need to be done first before there is delivery of other potential reforms, such as locational pricing.
- In considering radical changes, BEIS must be cognitive of realistic timeframes and whether they can be delivered in time to help us meet 2035 and 2050 targets. Government must be aware that projects with 10-year lead times will not be in operation until the early 2030s, and while we welcome steps taken to meet the 2050 target, other approaches may be required to meet 2035 targets.
- BEIS must ensure that it has good data on the reality of energy market operations, as well as theoretical assumptions – particularly when considering options for regional pricing which will be restrained by grid capacity concerns.

Chapter 4 – Cross-cutting questions

8. Have we identified the key cross-cutting questions and issues which would arise when considering options for electricity market reform?

Additional cross-cutting questions and issues

REMA identifies some, but not all, of the key cross-cutting questions and issues which are important when considering options for electricity market.

- *The consultation gives no attention or consideration to how REMA reforms might interact with the retail market review, and with Government proposals to address the energy crisis.* In this vein, it also fails to give consideration to the impact on vulnerable consumers, and how vulnerable or disengaged consumers can be supported to become more flexible. These are high-priority cross-cutting questions for the energy industry.
- *REMA gives little consideration to the impact on investor confidence and how investors' concerns could be mitigated so that renewable and clean technology projects continue to attract finance, in light of the requirements to deliver a Net Zero electricity system by 2035.This includes impacts of reforms on existing generation.*
- *The overall ability of different options set out in REMA to align with 2035 net zero power system targets should also be considered a key cross-cutting question.*
- There is also a further cross cutting question: *What physical infrastructure reinforcements will be required to see these reforms, and their overall objectives delivered?* The proposals in REMA seem to have been considered in isolation from the physical network upgrades that will also be required to deliver a future-proof Net Zero electricity system by 2035.

9. Do you agree with our assessment of the trade-offs between the different approaches to resolving these cross-cutting questions and issues?

- *We agree that BEIS has identified some of the trade-offs between the different approaches, however detailed analysis of the implications of these trade-offs is lacking and further analysis would be useful.* It is, however, recognised that full analysis of such trade-offs will only be possible once Government have properly identified their package of reforms and the interactions between the decisions made.
- For instance, the REMA consultation document acknowledges that it may be difficult to design a single market that 'fairly takes into account the very different characteristics of participating technologies', and that this may lead to some technologies being more successful within the market. Yet the document does not clarify that such differences are an important factor of a decarbonised and decentralised energy system. A wide range of low carbon and renewable technologies will be needed to play their role, providing both renewable and firm power. As such, market reform must encourage this diversity and address any market failures that could be a barrier to seeing crucial grid services delivered. A market that supports an appropriate and varied mix of technologies is essential for future-proofing the Net Zero electricity system's security of supply.
- *REMA must recognise that a range of contracts, of different lengths, will be required to bring forward the range of technologies required in a decarbonised system.* This also needs to be

approached with awareness of different lengths of projects and project lead time. For example, LLES contracts may require several years while other flexibility assets or generation may need contracts of only a few months.

- *It should be recognised that some renewable and low-carbon energy technologies are location-restricted due to geography, including offshore wind and solar. This is particularly the case for pumped hydro. Renewable energy development is also location-constrained by planning and environmental regulations.* Such requirements could undermine location driven market signals or other reforms. A system which leads to bias towards certain technologies over others will create constraints on where projects are incentivised to be developed, failing to utilise the full range of natural renewable resources that the UK's geography offers.
- *BEIS is correct in identifying that less developed innovative technologies (i.e. those newer technologies which find it harder to gain investor confidence in secure and stable returns) may need additional support to reach full commercialisation*. However, the REMA consultation document makes no reference to how these technologies could be independently and fairly assessed.
- *BEIS is right to note that some of the technologies within the scope of REMA will also play an important role in delivering benefits beyond the scope of REMA, such as industrial decarbonisation and economic growth in post-industrial regions, but it would be a mistake not to consider this an important factor in strategic decision-making, as REMA suggests.* Such criteria should also be considered as important factors in decision-making, particularly given the current economic situation, the rising cost of living and the need to contain energy prices to protect businesses and consumers.
- *Our storage members stress that REMA should recognise that there is value from a flexibility perspective in a level of price volatility being maintained, in the interests of market signals and incentives for flexibility assets. REMA must find a balance between consumer protection and necessary levels of volatile price signals.* Some level of volatility is required in the market to drive efficiencies and behaviour change. This is needed, for example, to maintain revenue streams for many energy storage assets. Moreover, demand reduction is a stated objective, but this is achieved through price signals in the market driving behavioural change, raising the matter of how far consumers must be insulated from price signals in the market and to what extent consumer protection may come at the expense of attempts to reduce demand. Consumers must always be protected from this where vulnerable and in fuel poverty.
- Storage members believe that this links to the ongoing Retail Market review, but a clear direction on demand reduction and flexibility must be better considered within REMA to determine whether a market solution is the best method of providing consumer protection or if this could be achieved through other tools available to the state. For example, if consumers were supported through the benefits system, this would allow the market continued exposure to price signals.

10. **What is the most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage? Please provide evidence to support your response.**

- Before the implementation of market based locational signals, physical grid upgrades and flexibility markets must be delivered so that there is a chance for developers to be able to respond to market signals. Failure to fix these physical limitations will undermine attempts to introduce effective market signals.
- One risk of locational pricing is that some developers could be tempted to buy up prospective sites and not develop them for some time, until demand increases sufficiently in the local area for the potential revenue from a plant to increase. Part of the current backlog of development is due to problems with Queue Management. Queue Management reform needs to be a urgent priority to address both transmission and distribution constraints.
- Project developers and investors would be able to factor in locational constraints into investment decisions more easily with better data transparency on locational capacity constraints. This could involve a data pool in a centralised and easy-to-access format. Providing early indication of what this data looks like and how it can be accessed far ahead of locational pricing being introduced will be essential for developing confidence in any final decisions around locational pricing.
- Wholesale market reform should encourage the co-location of electricity and other forms of storage projects, with renewable generation. This would help to manage capacity constraints on the local networks and smooth the peaks and troughs of demand. It is suggested that split market approach, could help this by giving priority to those with flexible assets and the ability to respond frequency response.
- Ancillary service reform and mechanisms for flexibility would better incentivise the delivery of flexibility. Our thinking on these areas is set out in Chapters 7 and 9.
- issues.
- Given the urgency of the required changes in several other areas, particularly flexibility, roll out of renewables and wholesale market reform, we believe the introduction of locational signals should not be considered an immediate priority. Focusing on wider market reform, including the decoupling of the marginal generation price and the roll out renewable generation, should be the primary focus.
- This will also allow time for modelling and cost benefit analysis to be completed and published, required to provide industry with greater understanding of the benefits or opportunities of locational market reform.

11. **How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.**

- Without further studies completed and better information provided to industry of what locational pricing will actually look like, it is difficult to say how responsive market participants will be. Initial feedback from members has largely been negative due to a lack of clear demonstratable evidence of what such locational signals will actually look like. There is concern that delivery of locational signals would likely deliver significant level of uncertainty in the first instance leading to a hiatus in investment and development that could damage decarbonisation efforts.

- If done correctly, with a high level of clear and accessible data to provide transparency, and a sensible transition period it is possible that developers at all scales of renewable generation projects could be responsive to locational signals. We have already seen some evidence of this in Scotland where TNUoS charges have effectively delivered locational signal for several years. TNUoS charges for onshore wind in Northern Scotland have soared 180% in 9 years, meaning that in an area of low population and high wind speeds, there is a perverse disincentive to develop generation.
- However, locational signals introduced by nodal pricing are likely to be undermined by physical constraints on the grid. Currently the physical ability to find a grid connection is the strongest locational signal acting on the market, and in swathes of areas there is a long queue to wait for a connection. Addressing a lack of grid capacity is going to be crucial for locational pricing to have any meaningful affect.
- The market's response to locational pricing signals will be dependent on there being transparency in seeing the signals delivered.
- We also note the concerns politically around the impacts on investment in less economically successful parts of the country by concentrating development nearest to population centres.

12. How do you think electricity demand reduction should be rewarded in existing or future electricity markets?

- The options set out in REMA are not mutually exclusive and REA believes a package of options is likely to deliver the best outcome for Net Zero.
- Electricity demand patterns can be partially smoothed by improving the energy efficiency of homes and commercial buildings, and by incentivising the consumer to use their appliances (e.g., to charge their EV) at times of relatively low electricity demand. Moreover, the deployment of flexible assets is essential. For example, thermal energy storage assets allow electrification of industrial heat using renewable electricity or power at points of low demand or high availability. We need to ensure a level playing field for all clean tech solutions and energy storage technologies.
- Suppliers are, to some extent, already innovating in this area using time-of-use tariffs. Though many consumers may need or wish to continue on fixed rate tariffs, enabling easy access this is one way in which electricity demand reduction can be incentivised.
- Communication from Government to the public needs to improve significantly about the benefits of installing energy efficiency measures, smart meters and other energy smart appliances that can enable users to make their demand flexible.
- REA notes that without a drastic scale up of domestic ESM (Energy Savings Materials) installations, including thermal energy storage, solar panels, batteries and EV chargers, there is a substantial risk that wealthier consumers will be the primary beneficiaries of time-of-use

Commented [CC1]: Add in ask on treatment of storage?

tariffs. The REA has been calling for a programme of investment in energy efficiency measures in social housing to help address the inequality. Ending many vulnerable consumers' dependence on pre-payment meters will also be essential to ensuring the possible benefits from participating in time-of-use tariffs can be accessible to less wealthy consumers

Chapter 5 – A net zero wholesale market

13. Are we considering all credible options for reform in the wholesale market chapter?

- It is accepted that options provided are reasonably comprehensive, however there needs to be greater clarity about how they could interact with the options set out in Chapter 10.
- Further modelling and analysis of each of the options, and how they interact with other options set out elsewhere in REMA, would be highly beneficial to further develop industry's understanding of which are the most suitable options.

14. Do you agree that we should continue to consider a split wholesale market?

- Yes, pending the further details and analysis of possible designs, the REA are supportive of seeing a split market considered further. If carefully designed, with a suitable transition period in place and appropriate arrangements made to protect existing low carbon generation, it seems likely that a split market could deliver effective market signals that decouple the cost of marginal generation, while prioritising and rewarding domestic renewable generation.
- However, there are a number of concerns that will need to be considered in the design of a split market:
  - It is not clear in the description of a split market how such a mechanism would impact industrial consumers heavily reliant on predictable firm power, especially if reliant on power to produce industrial process heat. It will be important that a spilt market helps reduce the costs of industrial processes.
  - It is important that renewables are in no way seen as a 'secondary´ generation source due to the split market design, with a firm market dominated by fossil technologies only. As such, it is important that all low carbon technologies, where able to, are allowed to contract within the firm power market. This will allow the co-location of storage with variable generation to contribute to firm power generation and help deliver a long duration energy storage sector.
  - It is important that existing generation and their business models, including revenue streams, are appropriately protected within a new market design. While existing support mechanism can be grandfathered, it will be the tail end of projects life, once they have come off RO, FiT or CfD support, that could be most disrupted by new wholesale market designs. Revenue from this period would have been modelled based on market

operations today, meaning that wholesale reform risks undermining these early investor assumptions. This needs to be guarded against.

- We encourage BEIS to consider what a split market design is attempting to achieve. There seems to be two main objectives, first to insulate consumers from high marginal prices, and second to protect generators from cannibalised prices in the future. It should be noted that the CfD by itself does split the market in this way and provides the insulation being sought. Further exploring the CfD for existing generation could be a better (quicker) solution than longer term larger scale market reforms.

- In addition, the REA also stress that clarity of approach and setting out a sensible timetable for delivery of a split market is crucial. In order to deliver a Net Zero electricity system by 2035, construction of certain large-scale projects needs to start imminently. There is concern that any uncertainty could deter investment in projects, and projects with a long construction time could be particularly vulnerable to investment hiatus, while they are needed to reach a Net Zero 2035 goal.
- As discussed in our response to Question 4, We would like to see a timetable of the consultation processes for the reforms and a timeframe for transition periods, as well as work undertaken to analyse which changes might be appropriate to be brought into action more quickly. The current crisis highlights the importance of undertaking the reforms within a prioritised timeframe, but we are keen that the Government should plan for wholesale market reform with an appropriate level of consideration, given that the new system must be fit for purpose for decades to come.

15. How might the design issues raised above be overcome for a) the split markets model, and b) the green power pool? Please consider the role of flexible assets should play in a split market or green power pool – which markets should they participate in? – and how system costs could be passed on to green power pool participants.

- *In our members views, there are a number of possible issues with the Green Power Pool. In particular, while it could provide a flexible and low commitment option for generators, it's voluntary nature significantly reduces incentives for generators*. Generators are unlikely to move into the Green Power Pool while prices are high.
- It is also unclear, from the limited description set out in the REMA document, how the benefits of a Green Power Pool would be felt by consumers.
- In both designs, there are also possible issues with social equity and the impact on vulnerable consumers. Both approaches are built on the assumption that consumers will be flexible and able to participate. There is a risk with the split market, that customers who aren't able to offer flexibility (such as pre-payment meter customers) will be forced to pay higher costs.
- It will be crucial in both designs that flexible asset, including storage multiple durations are able to participate in the firm proportion of the market. The wholesale market will then need to be complimented by deep and transparent flexibility and balancing markets so that

additional grid services, beyond power production, are also appropriately rewarded. This in turn will also help to keep wholesale costs low.
- We would need to see consider the design risks of the split markets model further to provide additional input on this question.

16. Do you agree that we should continue to consider both nodal and zonal market designs?

- We believe further modelling and cost benefit analysis of both options is required to properly consider the benefits or weaknesses of locational pricing. Without such analysis it is not clear to the market that locational pricing has strong enough advantages to be worth pursuing, or whether there is significantly more benefit to be realised by going down to nodal level pricing.
- So far we have not seen how the challenges of either market design could be adequately mitigated, and we set out our concerns around introducing locational pricing below. We support further investigation and provision of analysis to industry by BEIS on how these market designs could work in practice. Concerns must be worked through open-mindedly in consultation with industry before locational pricing is further pursued.
- REA acknowledges that under the current market design, interconnectors, generation and electricity storage can be incorrectly incentivised and sited, exacerbating constraint. For instance, at times of high demand, the high national wholesale price for electricity can incentivise storage to reduce demand in low demand locations. However, such analysis must also consider geographical and physical grid realities. It makes sense to develop generation close to existing demand, and the current wholesale market design contributes significantly to constraint costs and inefficiencies in balancing the network, aging grid infrastructure plays a major part in these problems too – arguably, it underpins them, and any move towards nodal or zonal pricing must come alongside significant network reinforcement and/or flexibility asset solutions with the same affect.

  For the most part, while it is recognised there could be some useful market signals produced by locational pricing, on the whole the Industry remains concerned about the practicality of its delivery and the impact that it would have in complicating business models and in turn deterring investment. Any future proposals set out by BEIS regarding locational pricing must address the following concerns:

  - Transparency of price signals for business model development across the lifetime of a project – locational pricing could substantially complicate business models for developers, requiring the development of more localised knowledge and expertise. Price uncertainty and the variability of pricing across the life of a project could also be an issue – if nodal prices were unstable across the network and not forecastable over a 5-10 year period ahead, this would make it challenging for developers to identify the best locations to build new projects.

- Similarly Locational pricing will likely make it harder for developers to explain predictable revenues to investors. A poorly planned introduction could lead to a substantial investment hiatus as investors get used to the new system and confidence in the stability of the UK's electricity market decreases, just at the time when investment in low carbon electricity generation needs to be accelerated. High levels of data transparency will need to be delivered alongside regional pricing from the start of implementation.
- There is a need for better evidence on how nodal pricing would impact existing generators and existing investment. This is particularly relevant in the context of development of strategically important innovation such as BECCS or Hydrogen, that is being developed based on current models. The lack of transparent information could place uncertainty over project delivery. Reforms of TNUoS could be a better approach with this in mind.
- The increased complexity of such a system may make it harder for smaller developers and community energy groups to navigate, therefore weighting the system towards larger developers who would be better resourced to navigate the system.
- Risk that it would not have the intended outcome of incentivising new generation in high demand areas. These areas tend to be regions with greater scarcity of land, such as urban centres. As such, no matter the market signal, it may not be physically possible to deliver the generation required, while it simultaneously becomes too expensive to build generation where there is space. This could end up having the unintended consequence of disincentivising new generation or flexibility capacity from being built overall..
- BEIS must consider how this would interact with workstreams such as Queue Management reform.
- BEIS must also clarify how access rights would operate in a nodal market system – e.g., could projects buy access rights in an unavailable/low profit area and bank these until it becomes available or demand increases.
- We are concerned that smaller projects, not protected by a CfD and without access to the scheme, may face the majority of the negative impacts of locational pricing while larger generators will be shielded from the impacts.

17. How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?

- One significant issue with zonal pricing is the requirement to re-zone at regular intervals to effectively capture congestion costs. There would also be an 'ongoing regulatory risk from debate on whether and where to redraw zonal boundaries' (National Grid ESO Markets Forum, 'Net Zero Market Reform – Phase Three Consultations', 22 March 2022) – however this would be in line with continued conversations within industry around other regulation and policy, albeit with clearer price and profit implications. This could be mitigated by setting out clearly the independent role of the Future System Operator and possibly providing them with the overall powers to rule on relevant boundary decisions.
- We note that the principal examples of where nodal pricing has been implemented in the past (or is in the process of being implemented) concern much larger geographical areas. Implementation over a much smaller area within the UK could lead to greater confusion

amongst consumers as to which node they are covered by. Again, high levels of data transparency will be necessary to overcome such design issues.

- It is worth noting that in some areas of nodal pricing implementation, such challenges are dealt with by ensuring that consumers are less exposed to nodal prices – for instance, under the Ontario model consumers can opt-in to nodal prices, and under the California model pay one of three prices as per the states three nodal utilities, with the price derived from the nodal weighted average price for that region. Yet, it should be again noted that both regions are substantially larger than the UK. In the UK, customers who are paying under nodal pricing could suffer greater volatility and confusion due to the smaller size of the area involved.
- The nodal (and zonal) models presume that consumers will be able to be flexible with demand. To make such an assumption viable, Government must ensure that the majority of households do have smart metering in place before implementing locational prices, at least ensuring that they could theoretically take advantage of flexibility smart products.
- Moreover, the government should pursue a system that adequately rewards flexible assets for the benefits they provide to the system. This can be addressed through the introduction of deep, transparent flexibility markets.
- The development of nodal pricing must be accompanied by digitalisation and better data sharing in electricity markets. This will help to make market signals clear to all participants, not only those with the resources to access and analyse localised demand/generation signals.

18. Could nodal pricing be implemented at distribution level?

- We believe that, if introduced, nodal pricing would first need to be done at national and transmission level before any decision was made on moving towards it at distribution level. It's impacts at transmission level will provide a guide then for whether beneficial to pursue at distribution level.
- If pursuing distribution level locational pricing it is important that it is recognised that DNOs are private companies and it may not be in their commercial interest to develop a unified approach and systems. Different approaches across DNOs would further complicate nodal pricing for developers and generators, especially for smaller-scale companies and community energy. As such, it will be essential that a standardised approach is pursued from the beginning, likely determined and led by the Future System Operator working in conjunction with the ENA and other industry bodies.

- Overall. We recognise that there could be substantial benefits to locational pricing, in theory. These would include the avoidance of costly re-dispatch and the incentivisation of flexible demand from end-use consumers (though some daytime patterns of use will remain inflexible). We understand that one argument for nodal pricing is that it would help to optimise investment signals in network and generation capacity. We also recognise that the intention and theoretical benefit of nodal pricing is to incentivise long-term investment in renewable generation in high-price areas.

However, there are significant challenges to moving to a nodal system and BEIS has yet to set out how these might be adequately addressed. Our concerns include:

- We are yet to see a clear vision for how investor confidence can be maintained, or how such as system could avoid favourable bias towards larger renewable energy developers with greater in-built resources to handle a more complicated system, and for how distribution networks might be equipped to handle fluctuating and additional volumes of applications for plants in high-price areas.
- Further to this, there are a number of related behavioural changes that may happen as a result of locational pricing. As asset owners and developers, it is difficult to model these changes and this is likely to raise concern in the market and mean that borderline projects are unlikely to advance, stifling deployment. Margins on projects are often very tight, meaning if revenues are impacted in the region of 3-5% project viability may be undermined. There is also a lack of transparent information on the impacts of nodal pricing and this uncertainty could have similar effects on project delivery.
- Nodal pricing may be a market-solution approach to a physical problem of aging and inadequate network infrastructure. The network infrastructure needs substantial upgrade as a priority before locational pricing is introduced, and grid capacity constraints mean that generation cannot locate closer to demand in the manner that the system intends to incentivise. Moreover, location of generation could be locked in by many factors beyond grid signals, including resource availability and offtake need.
- We believe that the objectives of locational pricing need to be better set out. For example, if locational pricing is driven by constraint costs that are the result of a lack of infrastructure investment and flexibility, this could be better dealt with by investment and delivery of national flexibility markets.

19. Do you agree we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

- Our concerns and understanding of the possible benefits are the same as towards nodal and zonal pricing. In addition, because the local markets approaches set out in REMA have never been implemented in practice, there would likely be an even greater risk of an investment hiatus from the local markets approach. Designing implementation and the transition period would likely also take longer, as there are no known real-world examples to draw from.
- The voluntary nature of Thomas Pownall's model makes it more attractive than Olivella-Rosell's model, however it could introduce additional complexity to the market if generators were operating under different systems. The main challenge of this model would be whether DNOs could develop uniform approaches as private companies, when it may not be in their commercial interest to do so. If their approaches and systems for administering this local

markets model were different, then that would introduce even more complexity into the system and make it harder for developers and generators to navigate – likely a greater challenge for smaller companies.

- We are against Olivella-Rosell's model being continued to be considered because it:
  - Is not optional and therefore has the same risk of deterring investors as nodal and zonal pricing, but in addition it has never been implemented before and so would have an even higher risk and would require very careful design.
  - The option for consumers who are connected to the local grid to participate is theoretically laudable but in practice, with the roll-out of energy smart appliances still very unevenly distributed across social groups, could disadvantage more vulnerable consumers.
- As stated above in our answers to other questions, the local markets approach may be a market solution to a physical network problem. The network infrastructure needs substantial investment.

20. Are there other approaches to developing local markets which we have not considered?

No comment on this question

21. Do we agree that we should consider reforms that move away from marginal pricing? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

- Yes, we agree that reforms must move away from marginal pricing. With high renewables deployment and the transition to a more flexible decentralised energy system, it is no longer appropriate for marginal signals, especially those based on fossil generation, to set the wholesale price. Such a transition will allow for the low costs of renewable generation to be better represented in wholesale prices and deliver benefits for domestic and industrial consumers.
- However, pursuing such a change must be done carefully, recognising that existing renewable generation assets have business models based on existing arrangements. Revenues for such sites must be protected while transitioning to a reformed wholesale market to maintain investor and developer confidence.

We are also clear that such reforms should be focused at the national and transmission levels first, before considering moving on to distribution network level.

Finally, given the current cost of energy crisis, it is appropriate that reform is prioritised and delivered in a sensible time frame, bringing benefits to consumers as soon as possible. However, that does not mean that reforms can be rushed and as such must continue to be well-thought through with a sensible and realistic, but urgent, timetable put in place.

22. Do you agree that we should continue to consider amendments to the parameters of current market arrangements, including to dispatch, settlement and gate closure?

- We understand that theoretically, shortening the time between gate closure and dispatch allows greater opportunity to balance supply and demand economically.
- REA believes that in theory shortening gate closure time could facilitate greater innovation by the market
- We would like to see greater modelling and analysis of possible options for these areas

23. Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?

- A range of contractual lengths need to be introduced into the market. While short contract durations of a day, week or month for balancing and ancillary services have been helpful in some cases, they do not enable bankable business cases for longer duration energy storage projects). We would welcome the introduction of stable, long-term contracts for flexibility services.
- Longer and Larger Energy Storage (LLES) technologies will often stack multiple revenue streams in order to build an investment case. Reforms that increase the clarity over revenue stacking will help to improve the investability of LLES. In particular, it is important that these technologies are fully rewarded for all the benefits they provide to the system, for example, arbitrage, inertia, short circuit level etc.
- A voluntary CfD should be explored further to immediately meet objectives on market design, namely the protection of consumers and generators by providing a stable market price and certainty of returns. This could be delivered alongside or preceding broader Wholesale Market reform.
- We support further exploration of the application of a more appropriate Carbon price applied in order to ensure that the cost of Carbon is a key factor when planning generation projects. This could create a single market by which fossil fuels are disadvantaged by price and lower generation costs of renewables is still recognised. This could take the form of an Emissions Added Tax.[3]

Chapter 6 – Mass low-carbon power

24. Are we considering all credible options for reform in the mass low carbon power chapter?

[3] https://www.storelectric.com/incentivising-clean-energy/

- We believe that a variation on the CfD mechanism (which has been highly successful so far in delivering large amounts of renewable generation) is likely to be the most appropriate choice, but would welcome further information and analysis on this and on the other options.
- A first step in reforming the CfD would be the option to contract generation more regularly than on an annual basis. This could be delivered first through more frequent CfD auctions, holding auctions on a 6-month basis would allow more low carbon generation to be brought forward. Second, the government could offer a voluntary CfD contract to existing generators, giving them the option to contract at a strike price much lower than the current Wholesale price and providing long-term certainty in revenue streams for generators.
- We agree that these are the best options for reform, but all of them would require very careful design and adjustments to ensure that they deliver a fully decarbonised grid by 2035, a future-proof electricity network, Net Zero technology neutrality, and the best possible social and economic benefits.

25. How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?

- CfDs have been critical to decarbonising the system thus far, and should continue to play an important role, with some reform.
- An approach that carefully considers the impact on private investor confidence is appropriate. Existing investments must be protected as reforms could see revenue streams changed significantly, generators must be protected from these changes.
- This could be achieved through offering generators a CfD on a voluntary basis at an appropriate strike price or through guaranteeing a minimum price during the full period of their investment. Both measures would ensure some protection from sudden changes caused by market reform.
- CfD variations could include lower pricing at times of low demand and a premium price during peak periods. This would incentivise investment in co-located projects and support deployment of flexible assets.
- We need better flexibility markets. Most of the proposed mechanisms for facilitating the deployment of low carbon power only reward power generation, reforms need to be made to ensure that generation is also rewarded for any flexibility services provided.
- The market and any mechanisms that support flexibility must incentivise the co-location of renewable electricity generation with electricity storage.
- Reformed electricity markets must also better reflect the advantages of a carbon price and incentivise a continual decrease in carbon emissions intensity across the market.

26. Do you agree that we should continue to consider supplier obligations?

- We accept that BEIS may wish to continue to explore a supplier obligation model, however without greater contextual understanding of how this would interact with any retail market reforms it is challenging to assess the value and impacts of a supplier obligation model.
- Timing and transition period would be key. Investment needs to continue to be incentivised, and short-term relief to prevent a hiatus may be required.
- We also would like to understand how balancing and constraint costs, along with network infrastructure upgrades, would be funded under the supplier obligation model.
- Overall, we believe CfD reform to be a more suitable and faster route to delivering the mass deployment of renewable technologies.

27. How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?

- This is difficult to comment on without understanding Government's intentions around retail market reform.
- It should, however, be recognised that such requirements may work to limit retail competition in the market. While reform is needed to ensure new small suppliers entering the market operate in a fiscally sensible way, there is still benefit to be seen in ensuring that competitive pricing can still be delivered to the market to ensure there remains pressure on lowering consumer bills. As such, a supplier obligation must not become a barrier to new, well regulated, market entrance.

28. How could financing and delivery risks of a supplier obligation be overcome?

We would like to note that there are risks beyond those that the Government has identified.

- How would such a system affect suppliers and generators at different scales? Under such a system, it's possible that larger suppliers might find it easier to strike good value-for-money deals with generators, than smaller suppliers. Small generators, including community energy, might find it harder to strike competitive prices as they would have less bargaining power.
- Mandating a trajectory of decreasing carbon intensity could also disincentivise suppliers from taking action to decrease their electricity's carbon intensity beyond the level mandated. We would like to see some analysis from Government on how suppliers can be incentivised to go beyond the minimum threshold. We agree that counterparty contracting could be a risk under such an agreement, however think this is likely to be less of a challenge with intermediaries pooling and hedging this risk.

- We agree that there is a risk, which we consider to be significant, that suppliers would favour tried and tested technologies, rather than take on the greater investment risk exposure of newer technologies that have only been recently introduced to the market and cannot offer returns as reliable as newer technologies. This is an important issue – as effective decarbonisation delivery will require continued innovation and incentives for investors to take risks on First Of A Kind systems. An expanded mix of technologies will be necessary to achieve full decarbonisation, to provide security of supply, to use the UK's existing resources to their full potential and to maximise the economic growth opportunities of decarbonisation, particularly as many renewable energy generation and energy storage technologies are either location-limited or best utilised at certain types of locations. For example, certain storage technologies will be well placed to use former mining locations.

29. Do you agree that we should consider central contracts with payments based on output?

- Yes, we support continuation of the CfD and believe that it could be reformed to become more effective. This should also come alongside reforms to incentivise flexibility deployment, CfDs reward power generation only and reform should reward generators for flexibility services provided to the system.
- A first step in reforming the CfD would be the option to contract generation more regularly than on an annual basis. This could be delivered first through more frequent CfD auctions, holding auctions on a 6-month basis would allow more low carbon generation to be brought forward.
- Through market reform, CfDs could be used to protect investment. Existing investments must be protected as reforms could see revenue streams changed significantly, generators must be protected from these changes to protect investor confidence.
- This could be achieved through offering generators a CfD on a voluntary basis at an appropriate strike price or through guaranteeing a minimum price during the full period of their investment. Both measures would ensure some protection from sudden changes caused by market reform.
- CfD variations could include lower pricing at times of low demand and a premium price during peak periods. This would incentivise investment in co-located projects and support deployment of flexible assets.
- The CfD should be reformed to better support smaller projects. At present, the administrative burden of CfDs present a disproportionate challenge to developers with fewer resources. Moreover, the milestones to be accomplished once a CfD is awarded need to reflect project development for a specific technology group and project size. Delays and funding uncertainty have a greater impact on smaller projects and historically, they have been unsuccessful at meeting the required milestones and have therefore lost the CfD. One solution could be to offer CfDs specific to individual technologies or scale of project.
- We need better flexibility markets. Most of the proposed mechanisms for facilitating the deployment of low carbon power only reward power generation, reforms need to be made to ensure that generation is also rewarded for any flexibility services provided.
-

30. Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?

Yes, and we believe that increases in financing costs will also be mitigated by decreases in technology cost , along with increased investor confidence where there is a clear direction of travel for more renewable deployment, overall leading to a lower cost of capital.

31. Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?

32. Do you agree that we should consider central contracts with payment decoupled from output?

- Further evidence is required to be able to support the Government's idea of a Cap & Floor mechanism for all renewable generation, specifically this requires greater detail on how renewable generation plants, co-located with flexibility services such as electricity storage facilities could be incentivised to be optimised. Otherwise, it is difficult to understand from a renewable generator's perspective, how the central contracts would incentivise maximum production of electricity.
- Therefore we do not currently see the benefits of this proposal.

33. How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?

If a cap is to be introduced, it must be in the form of a soft cap, which continues to reward generators for optimised behaviour and value to the grid. This may be at a lower value then revenue under the cap, but this will continue to deliver valuable generation. Equally, any form of generation support must work in connection with flexibility and balancing market signals, ensuring that benefits provided to the grid are also being rewarded to ensure the right behaviours are being promoted.

34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

- In a smart power system, the need for deemed generation, especially for large scale generation, should be limited. If deemed generation is used then rewards should be de-rated so that there is a clear advantage for becoming metered.
- Alternatively, this might require random inspection procedures of applications and plants to ensure that the realities of projects are as is set out on paper. This would likely fall under Ofgem's remit.

Chapter 7 – Flexibility

35. Are we considering all the credible options for reform in the flexibility chapter?

- The proposals cover a very wide range of technologies at different scales, which may require separate mechanisms of support to ensure a balanced mix of technologies, multiple storage durations and deliver the overarching objective.
- Ultimately we support reforms being focused on the capacity market to ensure the delivery of a wide range of flexibility services, but with additional support mechanism to enable nascent sectors to be become established. This especially includes the establishment of a Cap and Floor revenue mechanism for Long Duration Energy Storage, as supported by the majority of respondents to the Governments Call for Evidence on a support mechanism for LLES. Further research is required on how this could be used to support other flexible assets.

36. Can strong operational signals through reformed markets bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.

- Funding for innovation needs to continue. New technologies such as gravity batteries, sand batteries, thermal storage etc may need additional support through demonstrator projects etc, to reassure investors and be attractive to developers, so that these technologies can be market-ready. The REA encourage a technology-neutral approach between different forms of storage; the market arrangements introduced or modified under REMA should not advantage certain types of storage, as all provide benefits to the power grid.
- We note that there are clear encouraging lessons to be learned from the current Net Zero Innovation LDES competition, and that further similar competitions are likely to be necessary at different times in the decades ahead as the race to decarbonise the UK for Net Zero 2050 accelerates.
- In addition, further dedicated support beyond just market reform is going to be needed to deliver technologies of strategic importance, this includes a cap and floor mechanism for Long Duration Energy Storage systems.
- We note that Government is currently consulting on introducing business models to support hydrogen transport and storage infrastructure, recognising the crucial role of storage as a 'system balancer' in the wider energy system. Electrolytic hydrogen, in particular, is seen as especially valuable for power system flexibility and as a potential form of long duration energy storage. To enable hydrogen to play this role, it is critical that Government delivers the announced business model for hydrogen transport and storage sooner than 2025 to enable critical, planned hydrogen storage infrastructure to be constructed and operational by 2027.

Commented [CC2]: Frank, does this sufficiently cover off the parity argument from Tamsin?

Not sure we want to make the grid fees argument as I don't entirely follow it?

37. Do you agree we should continue to consider a revenue cap and floor for flexible assets? How might your answer change under different wholesale market options considered in chapter 5 or other options considered in this chapter?

- REA's initial view is that it may be necessary and beneficial to deploy different mechanisms for varying categories of flexible assets.
- REA's position is that an Income Floor mechanism may be the most equitable option for large-scale, long-duration flexible assets. We recognise that Government is likely to wish to introduce a Cap alongside the Floor. However, with caveats that careful design and additional support for new technologies will be needed to ensure Net Zero technology neutrality. We also note the need for thresholds within a cap and floor mechanism, smaller scale technologies may find it a significant administrative burden and other innovative technologies may now be supported elsewhere, such as under the Hydrogen Business Model.
- There is a good evidence base for industry support for a Cap and Floor mechanism, with the majority of respondents to BEIS' Call for Evidence on Long Duration Electricity Storage believing that a Cap and Floor was the best mechanism to support the deployment of these technologies (under the original consultation, this was defined as those able to discharge for at least 4 hours minimum).
- REA would also support a 'soft Cap' for technologies that are not widely deployed in the market at present – this would ensure that storage providers are still incentivised to optimise their technology performance above the cap. This may be especially appropriate for technologies that are new to the market and depend on investors who are attracted to riskier opportunities with the offer of possible higher returns.
- An Income Floor or Cap & Floor mechanism for medium and long-duration electricity storage could be a 'quick win' for Government, given that industry has already expressed a clear wish to see a mechanism for such technologies. Careful design would still be required.
- Such a mechanism could compliment and work in conjunction with capacity market reform to better reward a wider flexibility market.
- In terms of a Cap and Floor for all flexible assets, we believe that more research is required and encourage BEIS to not allow REMA discussions to delay the deployment of a cap and floor support mechanism for LLES.
- Government should also consider how the introduction of a Cap and Floor mechanism for flexible assets and for LLES interact with any business model introduced for hydrogen storage and transport (currently being consulted on).

38. How could a revenue cap and floor be designed to ensure value for money? For example, how could a cap be designed to ensure assets are incentivised to operate flexibly and remain available if they reach their cap?

- Setting a soft cap is one solution to this and redistributing the cap to be used in the sector could work, too. From our report: REA acknowledges that the Government may consider including a 'cap' as part of an income floor mechanism - in which instance a soft cap should be used to avoid disincentivising investment and wherein flexibility providers are rewarded beyond the cap for value offered, but to a lesser degree. This ensures that they remain incentivised to offer maximum value and optimisation of the system. Revenue above the cap could be used to support a wide shared across funding pots for a wide range of energy storage technologies.

- For instance, as we suggested in our response to the Government's Call for Evidence on Large-scale and Long-duration Electricity Storage, if an operator was required to pay back 1/3 of profits above the cap, they would still be incentivised to offer maximum value to the system, while also providing a contribution that would be returned to the consumer and the grid, ensuring that further benefits can be realised from LLES.

39. Can a revenue (cap and) floor be designed to ensure effective competition between flexible technologies, including small scale flexible assets?

- We are of the view that separate mechanisms or incentives are likely to be most appropriate for incentivising the development of flexibility at different scales. There are too many flexibility objectives to be supported by one mechanism. It is also true that the market is already facilitating battery storage developments, and so any mechanism will need to effectively incentive large scale, long-duration energy storage, which is currently not being delivered.
- Any inclusion of small-scale flexible assets in a Cap and Floor, which is unlikely to be our preferred option, must be done carefully, perhaps in tandem with other reforms that support small scale flexible assets such as domestic Demand Side Response.
- Reform to the capacity market should be used to support and contract flexibility services more generally, at multiple scales and durations.

40. Do you agree we should continue to consider each of these options (an optimised Capacity Market, running flexibility-specific auctions, and introducing multipliers to the clearing price for particular flexible attributes) for reforming the Capacity Market?

- Yes we support the further delivery of capacity market reform, with the potential to see different flexibility services rewarded through different auctions or the addition of multipliers.
- Such Reforms should be used to establish the flexibility market, while more specific mechanism like Cap and floor can be focused on areas of strategic importance such as the delivery of Long Duration Energy Storage.
- We also note that the REMA document asserts that interconnectors are out of scope, but the way in which interconnectors interact with the market is not. Key questions are how would interconnectors fit in this picture, and how could the carbon intensity of the electricity supplied through interconnectors be verified?

41. **What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?**
42. **Do you agree that we should continue to consider a supplier obligation for flexibility?**

- A supplier obligation for flexibility at all scales is unlikely to be Net Zero technology neutral or to encourage investment in flexibility from newer technologies. Yet there is a risk that if only delivered for small-scale flexibility, then a supplier obligation mechanism risks diluting DSR signals and supporting generation flexibility, or vice versa
- There may be some benefit from exploring this option further, but the Government needs to analyse the interaction with half-hourly settlement reform and broader retail market reform.

43. **Should suppliers have a responsibility to bring forward flexibility in the long term and how might the supplier landscape need to change, if at all?**
44. **For the Clean Peak Standard in particular, how could multipliers be set to value the whole-system benefits of flexible technologies? And how would peak periods be set? (see p.91 for information on Clean Peak Standard).**

- There is a risk that a Clean Peak Standard could effectively be a repeat of the TRIAD periods that existed before Embedded Benefits reforms. This was an attractive market but in the last few years of operation it became impossible to predict when the peak periods would be and its effectiveness started to break down for that reason. In the future, it is possible that low demand could be as much of an issue as high demand and that needs to be reflected with regards to the Clean Peak Standard. For instance, during the first lockdown on hot days balancing charges soared.

Chapter 8 – Capacity Adequacy

45. **Are we considering all the credible options for reform in the capacity adequacy chapter?**

- None of these options offers a serious solution to grid capacity issues, which are causing a backlog of projects waiting to be built. Waiting for a grid connection takes several years in many parts of the country.
- While these are all credible options for reform, the capacity adequacy chapter does not acknowledge that there is also a major infrastructure investment required to improve capacity adequacy.
- In parallel to major infrastructure investment required on the power grid, Government should also look at upgrades and investment required on the gas grid, to enable the full decarbonisation of the electricity system. Hydrogen blending into the gas grid initially, and repurposing of the existing gas grid to 100% hydrogen where needed, will be required to enable energy to be carried across the country, from centres of supply to

centres of demand, where this cannot be delivered via electrons. Whole system planning and careful consideration of the interaction between gas and electricity grid is vital to ensure existing infrastructure is used in an optimised way and new, targeted and more costly infrastructure is built only when essential.
Location of electrolysers should also be considered as locating electrolysis in zones of constrained power transmission is considered a key solution for reducing the costs of constraints and new network reinforcement (Afry, 2022).

46. Do you agree that we should continue to consider optimising the Capacity Market?

- Yes, we agree that BEIS should continue to explore this option and we think it is likely to be the easiest option for the market to respond to, as well as the best for prioritising low carbon generation and rewarding the ability to balance the grid. Reform of the existing system is likely to be easier to design and implement, and therefore where it achieves the desired objectives, it is preferable as it is less disruptive.

47. Which route for change – Separate Auctions, Multiple Clearing Prices, or another route we have not identified – do you feel would best meet our objectives and why?

- We would support separate auctions in the Capacity Market for low carbon technologies. BEIS may wish to explore incentivising collocation of generation and storage by establishing targets or offering a higher rate to generation plants collocated with storage. The Capacity Market has historically been around 10% of the business case for storage – it has been helpful but not significantly so because it's a small percentage of the revenue. To incentivise more flexibility the CM would have to add more to the business case for electricity storage plants.

48. Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?

- Additional measures are needed if the contract duration of the Capacity Market is not increased.

49. Are there any other major reforms we should consider to ensure that the Capacity Market meets our objectives?

- We need a substantial investment in both, power and gas grid infrastructure in order to facilitate these reforms to make a difference in capacity adequacy.

50. Do you agree that we should continue to consider a strategic reserve?

- We are open to BEIS continuing to explore a strategic reserve, however note that a strategic reserve should only be needed if there is an insufficient lead-in time to build plants and connect them to the grid, or if contract lengths are too short. The new system should aim to avoid these issues.

51. What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?

52. Do you see any advantages of a strategic reserve under government ownership?

- We can see some advantages for ensuring security of supply, but think it may not be the best mechanism for incentivising investment in low carbon generation, storage and consumer DSR.

53. Do you agree that we should continue to consider centralised reliability options?

- We are open to BEIS continuing to explore the centralised reliability option, however our preference is for a reformed Capacity Market.

54. Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.

55. Which other options or market interventions do you consider would be needed alongside centralised reliability options, if any?

56. Do you agree that we should not continue to consider decentralised reliability options/obligations? Please explain your reasoning, whether you agree or disagree.

57. Are there any benefits from decentralised reliability option models that we could isolate and integrate into one of our three preferred options (Optimised Capacity Market, Strategic Reserve, Centralised Reliability Option?) If so, how do you envisage we could do this?

58. Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.

59. Do you agree that we should not continue to consider a targeted capacity payment/ targeted tender option? Please explain your reasoning, whether you agree or disagree.

- Yes, we agree that BEIS should not continue to consider a targeted capacity payment/targeted tender option, for several reasons. Firstly, it is unclear how regular the tender process would be, and secondly, there is no indication in REMA on how the carbon emissions of the technologies would factor into the tender process.

60. Do you agree with our assessment of the cost effectiveness of a targeted capacity payment/ targeted tender option, and the risk of overcompensation? If not, why not?

- Yes, we agree with your assessment of this risk. However, we also note that the element of supporting local needs could help to encourage innovation in certain locations where it may be appropriate.

Chapter 9 - Operability

61. Are we considering all the credible options for reform in the operability chapter?

- We think that these are the options for reform. We are not aware of any other seriously proposed options.

62. Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?

63. Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.

- Yes, we agree that the ESO/FSO should be striking the optimal balance between long and short-term contracts.
-

64. To what extent do you think that existing and planned coordination activity between ESO and DNOs ensure optimal operability?

- We think that the ESO/FSO needs to continue to maintain central control and may need to take on a greater level of responsibility for coordination, as local balancing at distribution level becomes increasingly important.

65. What is the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward?

- As stated above, while there is scope for distribution level institutions to play a more active role in facilitating markets and maintaining operability, we believe that this should be centrally coordinated by the ESO/FSO. DNOs may have conflicts of interest that prevent them from designing organised and consistent systems across the distribution networks. Furthermore, the distribution grid relies on the transmission grid for back-up – it is dependent on centralised back-up which requires some level of central control.

66. Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this be best addressed?

Currently the CfD largely decouples Variable Renewables from the energy market such as ancillary services. At the same time, important engineering features from thermal mass generation have never been adequately rewarded and are required to keep the system running. We therefore believe there is a case for such capacity to be paid for services it provides.

Such services are from electricity storage and/or power electronics, as well as newer items of technology. For example it has been proven that battery storage can provide artificial inertia to the network and this should therefore be supported and compensated in future.

67. Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? Is so, how could this be achieved?

Yes. This will aid a more holistic system, as long as it is coupled with moves to decarbonise the Capacity Market so that higher carbon sites are not incentivised, given a new lease of life or over rewarded just by installing such capacity.

68. Do you think that co-optimisation would be effective in the UK under a central dispatch model?

Chapter 10 – Options across multiple market elements

69. Do you agree that we should not continue to consider a payment avoided for mass low carbon power?

- From an investor's perspective, a less radical option than a complete restructuring may be preferable.

70. Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?

- In-built carbon signalling could be a positive move for incentivising renewable energy investment from fossil fuel companies.
- Flexibility would have to be carefully defined under such a scheme, to exclude or gradually exclude oil and gas synchronous generation.
- The methodology for calculating carbon avoided would be crucial to the value and effectiveness of the scheme. For instance, oil and gas fuels have significant carbon impacts at the extraction and transportation stages, as well as during the end-use stage.
- This scheme could be reliant on Carbon Capture and Carbon Storage.
- CCCS schemes may also require management and monitoring to ensure that the carbon saved is reported accurately and to prevent fossil fuel generation from gaming the system.

71. Could the Dutch subsidy scheme be amended to send appropriate signals to both renewables and supply and demand side flexible assets?

- There is some concern that Auction by Cost of Carbon Abatement could primarily incentivise technologies that by implication support continued reliance on fossil fuel sources, such as forms of Carbon Capture and Carbon Storage. This would have to be designed very carefully so that a preference would be given to BECCS supporting technologies such as biomass or energy from waste, as opposed to fossil fuel generation.
- However REA recognises the benefits of a market with carbon-saving incentives at its core.
- Industry has expressed some concern that this scheme, along with the Equivalent Firm Power Auction scheme, could be too fractured to send clear investment signals.

72. Are there other advantages to the Dutch Subsidy scheme we have not identified?
73. Do you agree that we should continue to consider an Equivalent Firm Power auction?

- Industry has expressed some concern that this scheme, along with the Equivalent Firm Power Auction scheme, could be too fractured to send clear investment signals.
- As this scheme has never been implemented in practice, it is very possible that it would require more time to design and a longer consultation process with industry. Given the timescales on which major renewable energy and electricity storage projects are required to be delivered, and the construction times of many of these projects (often up to a decade), there is very little time to design the scheme and deliver it in time for the Net Zero 2035 target.

74. How could the challenges identified with the Equivalent Firm Power auction be overcome? Please provide supporting evidence.

Some of the challenges we have identified will not be possible to overcome - for instance that it has never been implemented before and is therefore likely to take longer to design and implement.

Clearly more analysis and study is required on this option before it can be considered.

Please don't hesitate to contact us for further information or to discuss this response in more detail.

REA, October 2022