CONSULTATION RESPONSE

EFET
European Federation of Energy Traders

BEIS consultation on Review of Electricity Market Arrangements (REMA)

10 October 2022

The European Federation of Energy Traders (EFET) promotes and facilitates European energy trading in open, transparent and liquid wholesale markets. We build trust in power and gas markets across Europe, so that they can underpin the sustainable and secure supply of energy and enable the transition to a carbon-neutral economy. EFET currently represents more than 120 energy trading companies, active in over 28 European countries. For more information, visit our website at www.efet.org.

Introduction

We support the ambition to ensure that the GB electricity market arrangements can deliver a resilient, low-cost and low-carbon power sector, and understand that the high prices experienced over the past year, the significant level of grid constraint costs, and the changes in the capacity mix as we transition to net-zero may lead to questions about the design and regulation of the electricity market. We also appreciate the efforts that BEIS has made to engage with stakeholders in the course of this initial consultation round under the REMA framework and we hope that this level of engagement will be maintained in subsequent stages of the review process.

In our view, the successes of the British Electricity Transmission and Trading Arrangements (BETTA) market design and of marginal pricing in delivering huge volumes of renewable energy, competition, and security of supply should not be dismissed or underestimated. As Ofgem state in their recent discussion paper on Net Zero Britain: "Over the last few decades, GB's energy system has been more reliable than ever before, while becoming more efficient and driving down costs". The market design has offered contractual freedom and fostered competition, both of which have led to considerable innovation, market efficiency, and the continuous development of market arrangements. Therefore, we would recommend that the current review process fully considers evolutionary approaches and makes a very clear case for change if it is to seek to implement a 'revolutionary' option.

Immediate implementation priorities

In this respect, there are three areas where there is broad consensus on the need for changes and where immediate action to improve the situation can be taken to the benefit of consumers.

- **Recoupling the UK exchanges in day-ahead** to provide a more robust price signal. EPEX SPOT and N2EX should re-merge their order books and organise a single auction in day-ahead as soon as possible. This would be a pragmatic, noregret solution in consumers' interest, as the current situation has led to a material decrease in day-ahead liquidity, greater operational complexity (incl. impact on cross-border trading), and hedging difficulties. Once this is done, this coupling could be extended to intraday as well.

- **Delivering more efficient cross-border trading arrangements with the rest of Europe.** As also recognised in the REMA consultation document, interconnectors are an important source of flexibility and security of supply. Therefore, we would encourage greater cooperation with EU neighbours (and we welcome the recent efforts to this effect at the recent Prague meeting). We would also urge for the improvement of trading arrangements on the NSL cable with Norway, where currently there are arrangements only for day-ahead trading – it would be important to put in place intraday and forward trading arrangements as a matter of priority.

- **Strengthening the UK ETS and linking it with the EU ETS.** A strengthened and expanded UK ETS (as discussed in a recent consultation by BEIS) would have an enhanced role in driving the decarbonisation effort across the UK economy. The current lack of liquidity can be overcome by linking the UK ETS with the much larger and a lot more liquid EU ETS. We understand that the issue is compounded by the broader discussions on the post-Brexit relation between the UK and the EU, but there is a clear benefit to both sides of linking the two schemes. Moreover, linking would address any potential issues related to the implementation of the proposed EU Carbon Border Adjustment Mechanism (CBAM).

Low-hanging fruit for the short to medium term

Noting that an overhaul of wholesale electricity market arrangements would be a long-term project, we think there would be value in considering whether there are short and/or medium-term measures which may have a positive impact.

- Investigating the reasons for falling liquidity in the forward market and considering whether policy options to foster liquidity are available.
- Considering shortening the market time unit (i.e. 30 minutes at present) and/or moving gate closure closer to real time – benefitting flexible capacity and demand response.
- Aligning market rules across transmission and distribution and facilitating market adaptation to local congestions.
- Consolidating the number of ancillary services markets, making information more clearly available and enabling participation by a broader range of market participants.

Key concerns about the proposals for more significant reforms

- **Nodal pricing**

  We are concerned about the momentum that discussions on the introduction of nodal pricing seem to have gained before there has been sufficient analysis conducted on the wider indirect and distributional costs and given the uncertainty about the actual benefits. Further detailed analysis and consideration of implementation challenges, including what happens during the implementation period, is therefore required. We note that there would seem to be alternative ways of introducing further/stronger locational signals into the GB electricity market.

  Nodal pricing would represent a fundamental change in market design, requiring a move to central dispatch and large IT infrastructure investments. It is likely to impact competition and reduce forward market liquidity, and make hedging a lot more complex. It would also make interconnector operations more complicated, potentially impacting the development of an offshore grid. It may also impact existing contracts. Evidence of the impact of nodal markets on investment is mixed and it is likely that quite significant changes to renewable support and capacity markets would be required.

  A zonal design, where today's national market is split into several zones reflecting better network constraints, may be a less radical option. However, its benefits should also be demonstrated convincingly, with that assessment considering the likely impact on liquidity, the overall welfare impact and the need to ensure predictability in order not to impact investor confidence. A move to a zonal design would also require revisions to existing contracts; a complex and costly process.

- **Split market**

  We are concerned that proposals for splitting the market presented in the REMA consultation document (e.g. Malcolm Keay and David Robinson's "two markets mode") would remove entirely the incentive for a category of generators to respond to market price signals. That would seem to limit forward liquidity and have potentially undesirable consequences such as producing when there is surplus renewable generation. Furthermore, since such solutions (at least to our knowledge) are only theoretical and have not been implemented anywhere else yet, and since important details on the design and possible implementation of such models are missing, it is difficult to see, at this point, how they could be applied in practice.

  In contrast, proposals for reforming the CfD mechanism to increase the market exposure for CfD-supported generators, combined with facilitating the growth of commercial long-term renewable Power Purchase Agreements (PPAs), including support for the growth of such contracts in the industrial, SMEs and other segments (through aggregation, credit guarantees, and potentially exploring the idea of a voluntary Green Pool (where, however, we would see a market-led Green Pool as a much more appropriate set up than one where the Green Pool is managed by the ESO)), seems to be a much more practical and efficient way forward.

We hope that the experience which our members have of operating in a wide variety of European markets will allow us to bring an interesting perspective to this discussion. We look forward to further discussing the important issues raised by the consultation with the BEIS team.

Comments on the consultation questions

Chapter 1

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

Yes, we agree with the vision for future market arrangements, as presented in Chapter 1 of the consultation document. We also support the BEIS view that markets are a critical part of delivering our future electricity system, and that all elements of electricity and energy policy, including improvements to the retail market strategy, will need to work together to achieve these objectives.

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

Yes, we fully support the objectives of decarbonisation, security of supply and cost-effectiveness, and we agree with the importance of reviewing existing electricity market arrangements to assess the need for improvements, which would facilitate the achievement of these objectives. Such a review needs to happen via an inclusive process that analyses the alternative choices and trade-offs based on a clear problem definition.

The process also needs to be comprehensive and involve BEIS, Ofgem, the Future System Operator (FSO), representatives of Distribution System Operators (DSOs), and a broad range of stakeholders, including market participants. We appreciate the fact that so far BEIS has facilitated such engagement via a series of webinars and conferences, as well as this consultation, and we hope this active interaction will continue in the future.

Chapter 2

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

Yes, we agree that the key challenges of a future electricity system are well-captured in the consultation document: we agree that the pace and breadth of investment in low-carbon generation capacity need to be increased; that system flexibility needs to be enhanced; that improved locational signals to minimise system cost may be needed; that retaining system operability would be essential; and that price volatility needs to be managed better. We also stress the importance of thinking across energy vectors and considering the interactions between electricity markets and gas markets, carbon markets, markets for hydrogen and decarbonised gases and the transport and agricultural sectors which all have a role to play in reaching net zero.

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?

In our view, the consultation document makes a clear case for improvements to the existing electricity market design. However, the need for fundamental changes is less clear. Therefore, as a first step, we would recommend considering how incremental changes to existing arrangements may target some of the identified concerns – either alongside (recognising that market design changes take very long time periods) or instead of more fundamental reform options.

Chapter 3

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

Yes, we would consider these to be the right criteria against which to assess options, and we would add "fostering competition and liquidity in wholesale markets."
Any market design needs to balance: 1) facilitating investment, 2) ensuring system operability at reasonable costs, and 3) fostering competition and liquidity in wholesale markets, and any design choice involves trade-offs between these aspects that require careful consideration.

A liquid and competitive wholesale market is helpful in achieving policymakers' objectives as it enables both generators and suppliers to manage their long and short-term price risk more efficiently and effectively. For example, a developer may sell forward renewable power in a PPA to enable new asset deployment and a non-domestic consumers may purchase power in a long-term corporate PPA to minimise its exposure to near term and volatile prices.

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

Yes, we agree with the organisation of the options.

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

The considerations for constructing and assessing packages provided in the consultation document seem reasonable. In case more fundamental reform options are adopted, the phasing and timing of implementation will need to be considered carefully to ensure successful implementation.

The role of politics in the energy market also needs to be approached pragmatically. The last year shows that energy is fundamentally political and that changes in market conditions can lead to rapid political responses. That may mean being clear on decisions about technology choices and recognising that some outcomes may not be politically acceptable.

Chapter 4

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

Yes, we believe the consultation document identifies the key cross-cutting questions concerning the options for electricity market reform.

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

The consultation document presents a wide range of issues and potential options for changes, and has captured a number of key tradeoffs. When assessing the tradeoffs between the different options, it would be important to evaluate their impact on 1) facilitating investment, 2) ensuring system operability at reasonable costs, and 3) fostering competition and liquidity in wholesale markets, as those would be preconditions for an efficient market design.

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.

Locational signals for the location of production or demand facilities (or the closure of existing facilities) could come through a variety of routes – with varying degrees of complexity.

- At its simplest, connection policies could specify where new generators could connect and state the lead time – pushing investment towards the best locations.
- Connection charges could also be used to send a signal about the requirement for network reinforcement, although this would require a change in the depth of the connection boundary.
- Transmission Network Use of System (TNUoS) – and to some extent Distribution Use of System (DUoS) charges – already aim to send a signal, though how effective that is is a matter of debate. One could also theoretically consider the way access to the network is granted.
- The Balancing and Settlement Code (BSC) did contain provisions for locational loss factors – which may not be an option now that Balancing Services Use of System (BSUoS) charges have been removed from generation.
- A locational element could be built into the capacity market (although the risk is this would split liquidity).
- The pros and cons of having more locational characteristics in the ancillary services or the balancing market, while ensuring a clear link to the zonal imbalance price, could also be investigated.
- Clearly changing the frequency with which or the geography within which prices are calculated could also create a locational signal.

- The voluntary market in granular certificates could also enhance locational signals by providing consumer-led demand for renewables (incl. small-scale distributed generation) and energy storage in locations where there is a higher demand for such assets, thereby helping to alleviate network congestion.

All designs involve trade-offs and need careful analysis of costs and benefits. Perhaps the question is to work out which of these would be most effective and easiest to implement – taking into account expected timescales for network reinforcement.

It should also be noted that offshore wind facilities already have a sharp locational investment signal not just in where they can get permits, but where seabed leases are auctioned, and this occurs years in advance.

Nodal Pricing

Nodal pricing would represent a fundamental change in market design. The existing self-dispatch arrangements would change and central dispatch would need to be introduced. This would require a large IT infrastructure investment.

Prices would be produced for each point on the system, with the price reflecting congestion. This might be expected to benefit congestion management, while having a less positive impact on competition. Hedging in a nodal market is complex and it is probable that a set of Financial Transmission Rights would have to be developed and implemented. Guaranteeing the liquidity of the node-to-hub hedging instruments has proved complex in regional US markets. Existing contracts may have to be amended in view of the changes.

We note that evidence of the impact of nodal markets on investment is mixed and that it is likely that quite significant changes to renewable support and capacity markets would be required. It is also unclear whether a nodal design would be compatible with the zonal market design in Continental Europe. This could add complexity to interconnector operation and could impact offshore grid development.

A zonal approach

A zonal approach, in contrast, where today's national market is split into several zones which reflect better network constraints, may be less challenging to implement than a nodal model, while bringing comparable results. It would also be compatible with the zonal market design of Continental Europe, where we already have examples of countries with a market split into several zones (e.g. Italy, Sweden, Denmark, Norway), which could serve as a useful reference.

However, potential benefits would have to be assessed against the likely impact on liquidity and competition. The process of defining the zones would also need to be based on a robust methodology that takes into account the impact on market efficiency and overall welfare effects. The zonal configuration would also need to remain relatively stable in the medium term if it is to enhance investor confidence.

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

Sharper locational signals could impact the location of production facilities and demand with a view to alleviating network constraints and mitigating the need for grid development, but to a degree. Some renewable energy technologies, e.g. offshore wind, may have a more limited range of locations where the weather conditions would allow for their development and where construction permits are possible. To an extent, this also applies to the possible locations for new large demand centres, while existing ones are usually not possible or often unlikely to relocate.

Sharper location signals may also result in more efficient dispatch of certain assets, such as interconnectors or electricity storage, so that these are able to help resolve constraints on the electricity network. The level of dispatch efficiency gained from a sharper locational signal would need to be compared to the current Balancing Mechanism, as well as some of the improvements listed in our response to question 10.

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

We are tempted to say in exactly the same way as any other form of market participant. It is not clear why any market should arbitrarily limit participation by any form of energy production or consumption. The price should reflect the value that a party causes or saves.

Unfortunately, at present, opportunities for demand response to participate in the various markets and timeframes remain sub-optimal. Access to multiple revenue streams, including wholesale, balancing, capacity, local flexibility, and ancillary services markets, would allow demand response to make a much more tangible contribution to reducing the need for costly network reinforcement and development.

Chapter 5

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

The consultation document does offer a comprehensive overview of the various options for wholesale market reform, including options for incremental improvements to existing mechanisms. In assessing these options, it would be important to consider the required implementation timeframe (radical design changes would take a number of years to implement), the need not to disrupt investor confidence at a time when rapid decarbonisation is required (implementing reforms, which would require considerable changes to existing contracts or would create uncertainty for investors and developers planning to make investments today, would be disruptive for the continued and accelerated growth of carbon-free and low-carbon assets), and the likelihood and potential costs of unintended consequences when implementing radical changes, some of which would be implemented for the first time (e.g. splitting the market, at least to our knowledge).

Furthermore, we would like to reinforce the point made in the consultation document that it would be essential to consider how any reforms to the wholesale market, as well as reforms to investment support mechanisms, may impact liquidity, particularly forward market liquidity, as that would have implications for the ability of both producers and consumers to manage short-term volatility risks.

Getting the operational signals for flexibility right is also key, as that could help to accelerate the pace of decarbonisation, while reducing network constraint costs. With this in mind, we have some reservations regarding proposals for radical reforms, such as introducing nodal pricing or splitting wholesale markets by technology, and would be keen to see more detailed assessments being made in the case of the former, and more detailed proposals being presented in the case of the latter.

In the meantime, it would be important to expand the work on potential improvements to existing mechanisms, as that could produce some helpful improvements already in the short term, with limited implementation costs and uncertainty about results.

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

We have some reservations as to the benefits of pursuing this option further, at least with respect to the proposals referenced in the consultation document, which lack detail on how this could be implemented. In particular, we are concerned that:

- It would seem to remove the incentive for a category of generators to respond to market price signals. That would seem to limit forward liquidity and have potentially undesirable consequences such as producing when there is surplus renewable generation.

- If the expectation is that all low-carbon generation is financially backed by CfDs, it would essentially require the government to underwrite all capacity and remove the option to deploy low-carbon generation on a merchant basis. At a point when renewable energy costs have fallen significantly (in part thanks to support mechanisms), this seems like an inefficient outcome.

- If there was a price based on the average of the two markets, price signals would be blurred. This could mean that the signal to produce in times of scarcity would be insufficiently strong, impacting the demand side and flexibility providers.

Given the GB market will become increasingly renewable over time, it may be worth considering how you would ensure competition and reliable price signals in a market for non-renewable capacity.

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 flexible assets should play in a green power pool – which markets should they participate in? – and how system costs could be passed on to green power pool participants.

We would be interested to review proposals on how such issues could be overcome and would invite proponents of these proposals to elaborate further in view of the reservations we have expressed in our answer to question 14.

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

As explained in our answer to question 10, the introduction of a nodal market would constitute a fundamental change in market design. The existing self-dispatch arrangements would have to change to central dispatch, considerable IT infrastructure investment would be required, hedging in a nodal market is complex, and developing a liquid virtual hub may not be straightforward, and changes to existing contracts are likely to be required. Moreover, evidence of the impact of nodal markets on investment is mixed and it is likely that significant changes to renewable support and capacity markets would be required. There will also be strong effects on trading through the interconnectors. Lastly, the inevitable distributional effects would also need to be addressed and the solutions are likely to reduce the potential benefits of having such sharp locational signals. With these concerns in mind, we are more included to recommend focusing on alternative options for improved locational signals.

A zonal design which reflects better transmission network constraints may bring results comparable to the key benefits of a nodal design (improved locational investment decisions and dispatch decisions, reducing to an extent the need for network investment and redispatch costs), while reducing the concerns around the introduction of nodal prices mentioned in the previous paragraph. Nevertheless, an impact on liquidity and competition is likely, and drops in liquidity increase transactions costs and translate into higher costs to consumers. Changes to existing contracts may also be required, which also involves costs. Therefore, when considering a new zonal configuration for the GB market, it would be important to assess overall welfare effects, in addition to the potential benefits in terms of reduced network constraint costs and grid investment needs. Questions around the delineation of zones and the stability of zonal configurations over time would need to be considered.

We would also recommend having a closer look at alternative measures that could help enhance locational signals, such as the ones we discussed in our answer to question 10. Such incremental reforms may prove to be easier and less costly to implement, while bringing comparable results already in the short term.

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

We share the concerns about the nodal market design raised by BEIS in the consultation document, as explained in our answers above.

Regarding the zonal pricing model and the difficulties in defining the boundaries of each zone, we would caution against frequent changes to the zonal configuration, as that creates investment uncertainty. A balance would need to be achieved between the need to reflect accurately network congestion and the need for regulatory stability. Some lessons from the experience in the EU may be helpful.

With respect to dispatch efficiency, yes, a zonal design may produce less efficient outcomes compared to nodal pricing, but as already discussed, nodal pricing is likely to create inefficiencies in other ways, e.g. a negative impact on liquidity and more complex hedging, considerable implementation costs, and complex and time-consuming implementation.

So, while some challenges can be overcome, others would remain, and therefore, it would be important to weigh the overall benefits and strike a balance between alleviating constraint costs and ensuring continued market efficiency, competition and liquidity.

18. Could nodal pricing be implemented at a distribution level?

It is difficult to see why it would not be, were this approach to be pursued. However, it needs to be fully considered – including in light of Ofgem's consultation on distribution governance. It would seem perverse to create an arbitrary distinction between voltages and then to try and create an alternative approach to distribution pricing (flexibility market proposals today often look quite like nodal pricing).

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

Yes, we think it would be helpful to consider further the local markets approach. What is important here is that it is easy for assets and consumers to access all markets and potential revenue streams. This should be clear and automated/ automatic to the extent possible, i.e. where the energy is best used needs to be clear, particularly in close to real time, with short operational timescales.

It is also worth noting that some of the proposed approaches for the development of local markets involve a much more active role for DNOs. This would require significant changes, which need to be taken into account. An alternative approach would be for DNOs to engage more actively in the procurement of ancillary services at the distribution level on a competitive basis (much like in the case of the TSO), or for the development of local markets in a way similar to Pol Olivella-Rosell's proposal. Those would be complementary to wholesale markets.

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

It is important to recognise that several trials and alternative approaches are currently being trialled. BEIS may want to recognise this is an area where innovation is currently taking place and may want to ask whether there is a risk of constraining that innovation.

21. Do you agree that we should continue to consider reforms that move away from marginal pricing?

We do understand the concerns about marginal pricing both in cases of very high and very low prices, which has led to discussions around alternatives to the mechanism (it is important to note that the mechanism is used in day-ahead markets, with other electricity market timeframes being based on pay-as-bid pricing). However, it is important not to dismiss or underestimate the successes of the British Electricity Transmission and Trading Arrangements (BETTA) market design and of marginal pricing in delivering huge volumes of renewable energy, competition, and security of supply so far.

Marginal pricing is the approach used in the vast majority of power markets around the world, and it has been successful in the GB market because it:

a) Provides a strong incentive to reflect operating costs in bid prices;
b) Means that electricity will be produced from the cheapest generation sources;
c) Means carbon-emitting generation will only generate electricity when necessary to meet demand, even more so when combined with a market to price carbon emissions;
d) Allows part of the capital costs of investments to be recovered through inframarginal rent (which would otherwise have to come from subsidies);
e) For renewables in particular, contributes to their financing and reduces the need for public budgets to support renewable energy investors via subsidies;
f) Sends a signal about when and where new investment would be required;
g) Creates a transparent reference price which builds confidence in the market;
h) Gives a signal for consumption adaptation; and
i) Promotes innovation with a clear economic signal for investment in new technologies (peak generation plants, electricity storage, or conversion).

There are clearly concerns about the fact that gas is most often the marginal plant at present. In this context, a high wholesale gas price leads to a high electricity price and relatively high inframarginal rent for other technologies (depending on how they have hedged and the form of renewable support they receive – those with CfDs will pay back when prices rise). It is important to note that high wholesale electricity prices in the UK are being driven by a range of factors which include: (1) high gas prices due to the reduction in gas supplies from Russian; (2) concerns regarding the availability of nuclear power generation in France this winter; and (3) drought and high-water temperatures in certain rivers in Europe. These costs are passed on to consumers in the short term and we support helping those consumers that need it via targeted support measures which do not distort wholesale markets.

It may be worth reflecting on the signal that marginal pricing in the day-ahead market is sending. It is saying that any technology that is cheaper than the current wholesale electricity price can cover a proportion of its fixed costs via the wholesale market. The consequence of this is that: i) the incentive to invest is strong; ii) the amount of capital cost recovered via the market relative to subsidy schemes will be greater (meaning one might expect future renewable support auctions to clear at a lower price), iii) the incentives to innovate are very high. One might expect this to encourage demand response, storage and renewables – precisely the technologies which the GB system needs if it is to meet net zero, become more flexible, and be less dependent on gas. Hence, we think it is particularly important for BEIS to lay out why it considers that an alternative pricing method for the day-ahead market may be more appropriate and how that would be better able to deliver the benefits outlined above. We note that the Agency for the Cooperation of Energy Regulators (ACER) recently undertook a comprehensive assessment of the European electricity market because of concerns similar to those set out in the consultation document, and concluded that the market design was broadly fit-for-purpose (identifying 13 recommendations for short-term improvement).

An interesting thought experiment may be to ask whether the political response to the energy crisis would have been different had an alternative pricing mechanism existed. We would tentatively suggest that any pricing mechanism would reveal scarcity and thus run the risk of being deemed ‘unacceptable’ from a political perspective.

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

Yes, we would consider further examination of the benefits of such changes helpful.

Changes to settlement periods and gate closure to increase temporal granularity in the market would help to minimise disruption and reduce the costs of reforming the electricity market, as more radical reforms would inevitably be accompanied by higher implementation costs.

Shorter settlement periods could also help make prices more reflective of the actual market conditions, incentivising generation and demand to respond to the state of the system more frequently. Gate closure that allows generators to make their final positions more accurate could reduce the need for balancing action.

In our view, there are clear benefits to self-dispatch as opposed to central dispatch, as it allows for adjustments to be made under competitive pressure much closer to real-time, which is important for an energy system with a higher volume of renewables. Furthermore, changes to improve the Balancing Mechanism could also help to optimise the system and drive down costs that are passed onto consumers.

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

Besides power generation, the contribution of demand side response and storage in the delivery of balancing capacity and energy (FCR, FRR and RR) and non-frequency ancillary services must be possible. This requires that TSOs accept offers where market participants aggregate different capacities into a pool. Likewise, electricity storage operators should be allowed to bid into balancing capacity and energy auctions, including via pooling. The TSOs should make sure they allow market participants to link or make bids conditional to ensure that the widest diversity of capacity owners can contribute. Where barriers exist to the participation of demand response or storage to balancing mechanisms, these should be removed.

It will be critical to implement a harmonised coordination process between TSOs and DNOs to allow all assets connected to both grids to participate in all the ancillary services markets. Constraints at the DNO grid obviously have to be considered, but since markets will operate closer to real time, the procurement has to consider all validated bids for local flexibilities.

Also, the current Balancing Mechanism design tends to favour larger inflexible assets with higher remuneration than smaller inflexible assets – and this is something that BEIS should explore further.

Chapter 6

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

We support the efforts of BEIS to develop solutions that would increase the role of the market in accelerating the growth of low-carbon technology. Both providing greater exposure of support scheme contracts to prices and allocating financial support contracts on a competitive basis are essential for minimising costs to consumers.

In addition to what has been presented in the consultation document, however, we believe that opportunities for the market-based growth of renewable energy need to be explored further. The costs of renewable energy technology have fallen considerably over the past decade, which makes long-term renewable PPAs an appealing option for consumers (e.g. corporate or industrial offtakers), as they can fix their energy costs longer-term at competitive prices. In addition, renewable PPAs are also accompanied by valuable guarantees of origin that allow offtakers to make sustainability claims in relation to their energy consumption.

Only a small part of the renewable energy capacity in the UK is currently contracted under renewable PPAs, so there is considerable growth potential. At the moment, we are actually experiencing a sellers' market where we have more buyers than sellers. This is certainly a precondition for growth and means that a larger portion of renewable energy production could be underwritten by commercial entities rather than the government, which would help to reduce costs to consumers.

Renewable PPAs have a comparable effect to government CfDs for renewable energy developers, as they provide revenue stabilisation over a long period of time, which helps to obtain finance and reduce the cost of capital. At the same time, they remove the potential for market distortion of support schemes, as they are commercial contracts and do not take away all risks from the contracting parties: e.g. the balancing risk needs to be managed; incentives for hedging are maintained, which reduces the impact on forward market liquidity.

The regulatory environment could hinder the growth of renewable PPAs. Therefore, it would be essential to make sure that the revised low carbon power support mechanisms are complementary to and do not undermine incentives for the growth of commercial PPAs for renewable energy. It would also be helpful to improve the uptake of renewable PPAs among industrial consumers, SMEs, municipalities, etc. To this end, facilitating aggregation and addressing counterparty credit risk issues (potentially by providing help with credit guarantees), where required, would be needed.

Lastly, renewable energy producers are also exploring options for developing fully merchant renewable energy projects. This is not easy due to the preference of lenders and investors for longer-term revenue certainty in order to offer financing at more competitive rates. However, a robust energy market, offering clear price signals, the ability to optimise one's portfolio effectively close to real time, and opportunities for effective hedging in liquid forward markets, could improve the conditions for the development of fully merchant renewable energy projects.

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

This can be done by allowing such assets to participate more effectively in markets: access to different revenue streams, facilitating aggregation, the development of local markets, could all help value better the system benefits of small-scale distributed renewables. It is likely that many small-scale, distributed renewables have a value to the system, though it is unlikely this is universally the case.

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

The supplier obligation - or rather a "demand obligation," to avoid confusion with the Renewable Obligation - proposal, as outlined in the REMA consultation document, could potentially merit further examination, but as a supplementary mechanism in addition to renewable PPAs (the growth of which needs to be facilitated) and financial support allocated on a competitive basis through tenders and exposing generators to a greater extent to market signals to ensure cost and dispatch efficiency. Alongside such supporting measures, it might have potential to enhance the demand for renewables, while relying on commercial contractual arrangements and solutions that are already available in the market. It could help to improve locational signals and stimulate the growth of distributed generation, energy storage and demand response. However, caution about the ability of the retail market to support demand side measures and an assessment of whether such measures may favour large incumbents over new entrants would need to be carried out.

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 question needs to be considered in conjunction with the retail market review.

Hedging practices is one area that would need to be improved.

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

In addition to intermediaries (e.g. utilities or financial institutions), which are already providing such services, potentially, there could be a role for the government or other parties to play in addressing counterparty risk by providing guarantees where needed. Such measures should be taken in conjunction with retail market reform.

The proposal for the development of a voluntary Green Pool is interesting, but we do not see a need for such a Green Pool to be managed by the ESO. A market-led Green Pool would be a much more appropriate set-up.

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

Yes, as they have the benefit of being allocated on a competitive basis and the strike price structure of a two-way CfD reduces costs to consumers. However, increased level of market exposure for CfD-supported generation would certainly be very helpful. This could help to reduce the impact on forward market liquidity and increase incentives for more flexibility from such producers.

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

We would expect this to be the case, but this would need to be assessed in consultation with developers and lenders.

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

We are not able to provide a comment here.

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

This proposal is also worth exploring further, but its implications for the cost of financing would need to be assessed in consultation with project developers and lenders/ investors, and the question of how to design a revenue cap that does not remove incentives for valuable behaviour would need to be carefully studied.

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

We cannot provide a comment here.

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

We consider this option to have considerable disadvantages compared to alternative proposals.

Chapter 7

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

Yes, the chapter provides a good overview of the available credible options for reform. We would like to make the slightly pedantic point that flexibility is a very broad, and potentially misleading, term which can cover everything from options which provide system support in seconds (pumped hydro), to longer duration storage and technologies that can deal with, say, prolonged periods of low wind. All demand and generation can provide some flexibility, arguably a big part of the challenge lies in designing products or opportunities to participate in markets which can make use of this.

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.

Some low-carbon flexible technologies which have not matured yet may need additional support. It would be important for any such support to be allocated through competitive mechanisms that also ensure cost efficiency. The goal of any market design should be to send the right signals – both for investment and for operation. The extent to which this covers all investment costs can then be modelled and potential additional measures on the investment side considered if necessary.

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?

It is challenging to implement a revenue cap mechanism which would not destroy incentives to respond to operational signals and design such a mechanism in a meaningful way to apply across a diverse range of technologies. We are also not sure how such a mechanism would work for aggregated portfolios of smaller scale assets.

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?

In our view, designing such a mechanism in an effective way would be challenging.

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

In our view, designing such a mechanism in a way that could also work for aggregated portfolios of smaller scale assets would be challenging.

40. Do you agree that 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?

From the presented options, we would recommend studying further the option to optimise the Capacity Market, as the other two proposals would pose significant implementation challenges. With respect to the proposal for running flexibility-specific auctions, we are concerned that it would risk reducing liquidity, which could potentially increase clearing prices. On the other hand, the proposal to introduce multipliers to the clearing price for particular flexible attributes would be difficult from a calibration perspective.

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?

Response time, duration of capacity provision, and location could all be characteristics of flexibility that could be valued within a reformed Capacity Market with flexibility enhancements. There is an obvious trade-off here – the more flexibility is reflected, the more fragmented and less competitive a capacity auction could become.

42. Do you agree that we should continue to consider a supplier obligation for flexibility?

Yes, we agree it should be considered as an additional measure that could help to stimulate the market-based, demand-driven growth of flexible assets. The option would allow for competition across technologies and ensure that assets are exposed to price signals, ensuring efficient behaviour and cost-efficiency. Ways to address the potential impact on the cost of capital and counterparty credit risk need to be considered, however. Indeed, this could serve as a complementary mechanism to support low-carbon flexibility business cases and demand response.

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?

We have not considered the question in sufficient detail to comment. Our initial reaction is one of scepticism. We're not sure why you would limit potential providers of flexibility.

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?

We have not studied the case in sufficient detail to comment, but it may be worth exploring further.

Chapter 8

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

Yes, we think all credible options for reform have been considered. However, we are concerned about having more than one mechanism ensuring security of supply. We think a strategic reserve should not be the preferred option and instead, there should be a focus on ensuring the market-wide Capacity Market works well.

As far as cross-border participation to the Capacity Market is concerned, we recommend on two fundamental principles, namely:

- Effective direct participation of foreign asset owners/operators – generation, demand-response, storage – to the Capacity Market, with appropriate incentives and/or obligations on TSOs, where this effective participation depends on them;
- Equal treatment of foreign and domestic capacities contributing to the Capacity Market, with attention to the specific rights and obligations of capacity providers in the Capacity Market and, where relevant, related to energy market functioning.

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

Yes, we think that this could be helpful.

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 are concerned about the potential impact of such options on liquidity and would be interested in ideas how this risk could be mitigated.

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?

We are not sure how to answer this question – it depends on the volume to procure. But a narrow focus on capacity may exacerbate wider operability problems.

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

At this point, we do not see the need to consider other major reforms.

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

No, we do not think that BEIS should continue to consider a strategic reserve. We are concerned about having more than one mechanism ensuring security of supply. We think a strategic reserve should not be the preferred option and instead, there should be a focus on ensuring the market-wide Capacity Market works well. Also, recognised in the consultation document, a strategic reserve in itself does not drive low carbon investment.

51. What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?
In our view, the focus should be on optimising the Capacity Market.

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

No.

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

Yes, we think centralised reliability options should be considered further.

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.

We have not carried out such an assessment at this point.

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

No further suggestions.

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

Yes.

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?

We have not identified such benefits.

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

Yes, we agree.

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 with the reasons provided in the consultation document for not pursuing this option further.

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.

Chapter 9

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

Yes, we think all credible options for reform are being captured.

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?

To the extent that policies aim to facilitate the effective participation of low-carbon technologies and demand response in different markets, we would consider them appropriate. Improvements to product offerings is an important aspect, for instance. As to the extent that existing and planned policies are sufficient, that should be subject to further assessment and consultation.

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

Potential options for enhancing existing policies would merit further consideration.

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

In our view, the coordination of activities between the ESO and DNOs needs further improvement to ensure optimal operability. This would be particularly important for integrating wholesale and local energy markets, and for facilitating the participation of all market participants in all markets and timeframes. It would contribute to reducing the costs of balancing and ancillary services, optimising better the system and alleviating constraint costs.

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?

We would suggest that the concept of ‘distribution’ and ‘transmission’ level institutions is not helpful (not least as voltage definitions are different in England and Wales and Scotland). Fundamentally, the question seems to be what are the right governance arrangements for a single, integrated system applying the same set of rules (which can only be the long term goal). That will involve thinking about the role of the FSO and of DNOs/DSOs. Any network operator has a role to play in maintaining operability and facilitating markets, and communication and information sharing between them is crucial. We would generally recommend focusing on governance as part of this review.

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 best be addressed?

In line with the comments made in the consultation document, there could be such an impact.

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

We would be keen to understand why this disincentive is believed to exist and why mandating participation is seen as a solution. We would expect someone to want to seek additional revenue if there is a chance to do so. We would generally oppose mandating participation in markets.

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

We would support retaining the current self-dispatch model. There are clear benefits to self-dispatch as opposed to central dispatch, as it allows for adjustments to be made under competitive pressure much closer to real-time, which is important for an energy system with a higher volume of renewables.

Chapter 10

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

We do agree with the reflections of BEIS on this option, as presented in the consultation document.

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

We have not considered in detail the merits of such an option.

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

We have not considered this question.

72. Are there other advantages to the Dutch Subsidy scheme we have not identified?

We do not have any observations on this point.

73. Do you agree that we should continue to consider an Equivalent Firm Power auction?

We do not see much merit in considering this option further, as we do not see how it would add more value compared to what wholesale markets already offer, while it seems to limit flexibility. Improving access for all technologies to the different markets and market timeframes would have comparable benefits, while also offering greater flexibility and cost-effectiveness by allowing for the procurement of system security at a system level.

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

We have not considered this question in view of our answer to question 73. Our observation that it replicates to a large extent existing mechanisms while limiting flexibility, is a design issue, and we do not see how it could be addressed.