Consultation response

Review of Electricity Market Arrangements - second consultation

Response from the Electricity Storage Network

May 2024

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1 Background and contacts

Electricity Storage Network

The Electricity Storage Network (ESN) is **the industry group and voice for grid-scale electricity storage in GB.** The ESN has over 90 members who have a shared mission to promote the use of energy storage and flexibility to support the net-zero transition. The ESN membership includes clean energy developers, owners, investors, optimisers, and academic institutions. This includes representation from publicly listed specialist funds focusing on storage and independent developers that have raised several billion pounds to invest in this new technology class.

This response is based on extensive practical experience and input from our members involved in developing grid-scale electricity storage projects in GB. This has included but is not limited to a REMA working group, a REMA members workshop on 11 April and several one-to-one meetings.

About Regen

The Electricity Storage Network (ESN) is managed by Regen. Regen is a not-for-profit centre of energy expertise with a mission to support and accelerate the transformation of the UK's energy system to net zero. Regen has been a leading voice on the REMA debate over the last couple of years and has delivered several events, working groups and workshops to discuss these crucial issues. Regen has also responded separately to the REMA consultation.

1.1 Continuing engagement

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2 Executive summary

Below is a summary of ESN's key messages:

The case for a zonal wholesale market

- From our engagement with the GB electricity storage industry so far, **there is not a consensus in support of a shift to a zonal wholesale market system**. The industry is keen to see a detailed design for a zonal market in GB in order to be able to fully assess the potential impacts. This should include more detail on the number of zones and period for review, as well as impacts on embedded/distribution assets and intra-zonal impacts (as well as inter-zonal).
- **ESN does not support central dispatch** and judges that the operator/optimiser is best placed to understand and dispatch assets in the GB market.
- **ESN supports shorter settlement periods**, as the change aligns with the fast-acting capabilities of electricity storage technologies and their inherent flexibility. We think shortening gate closure should be retained as an option, as maintaining the current one-hour period would limit the potential benefits of a shorter settlement period.

Balancing Mechanism reforms

- We ask that Ofgem continue to monitor progress and hold ESO accountable for the pace of BM reforms, widening the role of low-carbon flexibility in the BM.
- We also ask that ESO publishes further datasets on transmission constraints to increase transparency ahead of the Centralised Strategic Network Plan.
- ESN calls for accelerating the timeframes to implement new storage parameters in the BM for limited-duration assets (Grid Code 0166).

New constraint management services

- ESN is very supportive of the development of new constraint management services, and several members have contributed to the collated list of market-based solutions in the ESO Thermal Constraints Collaboration project. We want to ensure this project shifts quickly to implementation and that oversight from Ofgem and DESNZ is maintained.

Capacity Market

- **ESN supports low-carbon minima with wider reforms of de-rating factors and Capacity Market governance**. ESN would like to have more specifics on how the low-carbon minima and the desirable characteristics would work in practice and the implications for the existing de-rating methodology.

Contracts for Difference reforms

- ESN members have flagged concerns that the impacts of potential CfD reforms, such as deeming, on ancillary services and the Balancing Mechanism have not been assessed in any detail. Significant changes to the market dynamics could undermine current business models and potentially reduce the deployment of low-carbon flexibility, making it very challenging to deliver government low-carbon flexibility requirements. We are, therefore, calling for further detailed analysis to be carried out.

Wider recommendations

- ESN is asking for an **overall target to be set by the government for grid-scale electricity storage capacity for 2035** in collaboration with ESO and industry.
- ESN is calling on DESNZ to reconsider the decision to drop giving the ESO/NESO the ability (or an obligation) to prioritise zero/low-carbon procurement in the REMA process.
- ESN believes there is a strong case for an update to the Smart Systems and Flexibility Plan, that aligns with REMA options and progress so far.

3 Response to the consultation

We have provided responses to the questions below and look forward to working with the DESNZ team on the next REMA reforms and implementation stages.

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

Response to questions 1-3

Q1. What growth potential do you consider the CPPA market to have? Please consider: how this market is impacted by the barriers we have outlined (or other barriers), how it might evolve as the grid decarbonises, and how it could be impacted by other REMA options for reforming the CfD and wholesale markets.

The use of long-term CPPAs was overlooked in the first consultation, so it is positive that the government have posed them as a credible market option for exploration as part of REMA, and they have been included in this second consultation. Although we believe that CPPAs will remain integral to hybrid financing models for large projects, barriers such as high counterparty risk, high transaction costs and contract length/demand mismatches restrict CPPAs to large, stable off-takers with good credit ratings and the ability to sign long-term contracts. The complexity of contracting arrangements and the tendency for smaller organisations to lack the resources and financial stability to take on a CPPA currently limits their ability to materially support the development of smaller-scale renewables.

In addition to exploring the role of CPPAs, the government should therefore consider the development and growth of the overarching long-term PPA market, which has become a significant enabler of renewable generation in the UK – an estimated 14 GW (24%) of UK renewable capacity is under PPA terms.[1]

Improving and expanding the PPA market should be a priority for forward-thinking market reform and will help reduce energy costs and market volatility, and encourage investment in low-carbon renewables. The development of the PPA market does not require significant changes to existing market arrangements. Instead, the government should work to encourage the market through regulatory and soft market interventions. For example, offering better guidance and information on PPAs, increasing market visibility and enabling public sector energy procurement.

The use of PPAs for stand-alone and co-located battery energy storage systems (BESS) projects has continued to develop in the GB market. This is likely to increase, and it is a key aspect of financing projects that do not receive direct subsidies.

[1] Aurora, 2022. Role of PPAs in the GB Power Market.

> **Recommendation:** Government should look to develop the wider PPA market, encompassing the development of CPPAs, to allow energy to be bought on long-term contracts at a lower cost. This should include storage PPAs.

Q2. Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.

No answer was provided.

Q3. Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.

No answer was provided.

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

Response to questions 4 - 13

Q4. Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address.

Q5. Assuming the CfD distortions we have identified are removed, and renewable assets are exposed to the full range of market signals/risks (similar to fully merchant assets), how far would assets alter their behaviour in practice?

The consultation describes some distortions related to dispatch incentives and a lack of incentives to use generation behind the meter or to offer ancillary services.

The distortion is related to the lack of incentives to use generation behind the meter, either through energy storage or behind-the-meter demand. While this has been perceived as an issue for some years, we agree that the clarification on existing options for metering arrangements and proposals put forward as part of the CfD AR7 consultation have the potential to ensure that CfD generators are fully incentivised to use generation behind the meter if the expected value of that energy (e.g. the value of hydrogen produced from a behind-the-meter electrolyser, or the value of electricity at a later time if used to charge a battery) is greater than the reference price at the time of generation.

The second point often discussed in this regard relates to ancillary services, which require a generator to turn down its output. While we agree that there is a lack of incentive, we do not think it is clear how large the challenge will likely be. In the past few months, the relevant ancillary services markets have tended to saturate due to the increase in battery capacity. While the need for these services will rise significantly as renewable penetration increases, there is no reason to think that this will not continue to happen. Even if wind and solar farms were likely to act as ancillary service providers, those ancillary service markets would face the same issue as the wholesale market – they would have an overabundance of supply during periods of high wind or high solar. Prices tended to collapse to zero at the same time as prices were low in the wholesale market. These challenges would also undermine the current and future electricity storage projects that are being developed, which have based their business models on the expected levels of competition in these markets. Therefore, there could be significant unintended consequences of opening these ancillary services to a wider pool of participants. We feel that this needs to be further understood and that more analysis needs to be undertaken.

In addition, ESN members believe there is a potential tension between the proposed capacity and deemed CfD design and the wider flexibility requirements outlined by the government of up to 55 GW of short-duration flexibility and 30-50 GW of long-duration flexibility. The current grid-scale battery storage connected capacity of around 4 GW to the system and the considerable 100 GW pipeline with contracted connection offers has been based on business models in the current wholesale market, ancillary market design and CfD framework. Making significant changes to these markets could, if done in the wrong way, undermine business models.

> **Recommendation:** DESNZ undertakes analysis to identify the likely scale of renewable project contribution to ancillary services provision. This should include the potential unintended consequences on the wider fleet of low-carbon flexibility projects, including grid-scale storage.

As mentioned above, the government has again included a wider requirement for "up to 55GW of short-duration flexibility" and for long-duration flexibility "at least 30 GW, but potentially up to 50 GW" across hydrogen-to-power, LDES, unabated gas and gas CCUS by 2035 in this consultation. However, the wide mix of technology types included in these definitions of short-duration and long-duration flexibility does not provide any clarity to the market.

We repeat the recommendation to set a target for grid-scale electricity storage capacity by 2035 that we included in our response to the UK Battery Strategy in October 2023[2] and Long Duration Energy Storage Consultation.[3] We have the existing National Grid Future Energy Scenarios as a guideline to inform the levels of storage required, and we understand these scenarios are changing under the shift to the National Energy System Operator (NESO) in 2024 and beyond. This overall target would be a key part of the upcoming NESO Strategic Spatial Energy Plan.

> **Recommendation:** The government should set an overall target for grid-scale electricity storage capacity for 2035 in collaboration with ESO and industry.

Q6. How far will proposed 'ongoing' CfD reforms resolve the three challenges we have outlined (scaling up investment, maximising responsiveness, and distributing risk)?

Ongoing reforms refer primarily to the recent AR7 consultation. Proposals for new hybrid metering arrangements have the potential to better enable CfD generators to develop behind-the-meter energy storage and demand, helping ensure they are incentivised to optimise operation of a co-located system in a way that is more aligned with system needs. That approach will not affect the incentive to provide ancillary services. However, as noted above, DESNZ should further explore the degree to which renewable CfD generators are likely to provide ancillary services in future before using this as a rationale

[2] Regen/ESN, 2023 https://www.regen.co.uk/wp-content/uploads/UK-Battery-Strategy-Electricity-Storage-Network-response-FINAL.pdf

[3] Regen/ESN, 2024 https://www.regen.co.uk/consultation-response-long-duration-energy-storage-cap-and-floor-scheme/

for major reform. Investigating trade-offs and tensions between the need for low-carbon flexibility to be deployed and CfD reforms.

Q7. What specific gaming risks, if any, do you see in the deemed generation model, and do any of the deeming methodologies/variations alter those gaming risks? Please provide supporting reasoning.

The REMA consultation does not provide sufficient detail to enable us to come to a firm view on the suitability of a deeming methodology or the potential for gaming. See our answer to Question 5.

Q8. Under a capacity-based CfD, what factors do you think will influence auction bidding behaviour? In particular, please consider the extent to which developers can reflect anticipated revenues from other markets in their capacity-based CfD bid.

No answer provided.

Q9. Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q25 on which actors are best placed to manage the different risks?

See answer to Question 5.

Q10. Do you have a preference for either the deemed CfD or the capacity-based CfD model? Please consider any particular merits or risks of both models.

As outlined in Question 5, there is not yet sufficient detail available to assess the potential wider impacts on ancillary services and the unintended consequences on the wider investment landscape for low-carbon flexibility that risks undermining business cases.

Q11. Do you see any particular merits or risks with a partial payment CfD?

No answer was provided.

Q12. Do you see any particular merits or risks with the reforms to the CfD reference price we have outlined? Please consider how far the two reforms we have outlined might affect both liquidity in forward markets and basis risk for developers.

No answer was provided.

Q13. What role do you think CPPA and PPA markets, and REMA reforms more broadly, will play in helping drive small-scale renewable deployment in the near-, mid- and far-term?

No answer was provided.

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

Responses to questions 14-21

The Capacity Market, introduced in 2013 as a relatively simple subsidy mechanism to ensure sufficient capacity adequacy in the system, has become an increasingly complex market to participate in. We have heard from members that the high administrative burden and additional risks from new penalties, on top of the punitive de-rating factors and the associated methodology, may mean that asset owners stop bidding for new CM contracts in the future. This becomes particularly important at a time of capacity scarcity and very high clearing prices and would not be a good outcome for the industry as a whole.

Furthermore, including the initial REMA consultation, this is the fifth consultation on the topic of CM reform that we have responded to in the last two years. Many proposals have been introduced in those consultations which have not been addressed in this one and could have important implications for the success of the reforms proposed in this consultation. REMA represents an opportunity to holistically review and reform the functionality of the CM, which has been missed. We urge the DESNZ team to use the REMA reform process as an opportunity to reform the CM governance process to make it simpler and fit for the future, and to take a wider, strategic view of CM reform in the future.

On a broader note, CM reform in and of itself is unlikely to bring about the significant levels of flexibility required to realise a decarbonised electricity system without wider policy interventions, such as strengthened and coordinated price signals and bespoke mechanisms to support developing technologies. We therefore encourage the government to continue to take a cross-cutting approach to flexibility, ensuring alignment within policy objectives as well as the development of clear and coordinated price signals across a variety of mechanisms.

Q14. Are there any unintended consequences that we should consider regarding the optimal use of minima in the CM and/or the desirable characteristics it should be set to procure?

While our response to the initial REMA consultation stated a preference for the introduction of multipliers into the CM, we are supportive of the minded-to position to take forward a single auction with multiple clearing prices design, with a focus on introducing a minimum procurement target for desirable characteristics. This is due to the supporting documentation[4] suggesting that this is the most effective option for supporting the deployment of low-carbon and flexible technologies in the CM.

However, the second consultation highlights that ”*further work is under way to develop how minima should be defined and set (i.e. to procure low-carbon capacity and/or key flexibility capabilities)”.* Without a clear set of definitions and principles around the optimal use of minima within the CM, it is challenging to identify the unintended consequences of such an approach at this stage.

[4] Baringa Partners, Alternative Capacity Market Auction Designs, July 2023.

In our insight paper, we highlighted that if the purpose of the Capacity Market is to support investment in assets to provide energy security and resilience, then is important to ensure that the mix of assets that are built provides more than just capacity. This means moving away from a market design that considers all forms of capacity to be equal, and instead valuing a range of attributes that add to overall system resilience.

The introduction of a minimum procurement target could allow the CM to remain technology neutral while providing a value weighting towards certain attributes and capabilities that are of value to the energy system. This could include, among other things, diversity and responsiveness, but, as a minimum, this should prioritise low-carbon technologies. However, as Figure 1 highlights, the supporting documentation suggests that technologies such as hydrogen and biomass could be defined as low carbon. If such reforms are delivered without properly defining the conditions under which such technologies can be classified as truly low carbon (such as the source of hydrogen), this could lead to negative outcomes and deliver outcomes that are inconsistent with the government's 2035 target. Therefore, a clear and accurate definition and supporting methodology of what constitutes as low carbon is a vital prerequisite to successful CM reform.

Type	Category	Low Carbon	Low Carbon Sustained Response	Low Carbon Response and Reserve
Battery 0.5 - 3hr duration	Battery	Yes	No	Yes
Battery 4 - 6hr duration	Battery	Yes	Yes	Yes
Biogas and Biomass (inc CCS)	Bio	Yes	Yes	No
DSR	DSR	Yes	No	Yes
EfW	Gas	No	No	No
Gas CCGT, OCGT, CHP	Gas	No	No	No
Gas CCS	CCS	Yes	Yes	Yes
Hydro	Hydro	Yes	No	No
Hydro Pumped Storage	Hydro	Yes	Yes	Yes
Interconnector	Interconnector	No	No	No
Nuclear	Nuclear	Yes	Yes	No
Wind	Wind	Yes	No	No
H2 CCGT	Hydrogen	Yes	Yes	Yes
H2 OCGT	Hydrogen	Yes	Yes	Yes
Longer duration batteries	LDS	Yes	Yes	Yes
Longer duration, low efficiency (6hr)	LDS	Yes	Yes	No
Longer duration, low efficiency (12 hr)	LDS	Yes	Yes	No
Established longer duration storage (medium)	LDS	Yes	Yes	No
Established longer duration storage (long)	LDS	Yes	Yes	No

Figure 1: Provisional definitions for different technology types participating in the CM, provided as a starting point for further policy exploration. Source: Baringa Partners, Alternative Capacity Market Auction Designs

Members also highlighted the importance of setting long-term targets within the CM that industry can respond to, with a lack of strategic direction currently hampering investment decision making. While the introduction of minima can provide a level of flexibility, with different characteristics prioritised to a different extent each year, a horizon of two to five years with clear procurement targets would provide a greater level of certainty to allow for industry to adapt.

Finally, the process of bidding into the CM already involves a high administrative burden, and the introduction of minima with more than one desirable characteristic (low carbon, sustained response or response time) could materially increase complexity if this process is not properly managed, with the potential unintended consequence of reducing liquidity if participants feel it is no longer sustainable to participate. This is something we discuss in more detail in our response to Q15.

> **Recommendation:** Further details regarding how minima will be defined and set, including a clear definition of low-carbon technologies, should be provided by the government as soon as possible for industry to review. This should include the provision of a greater level of strategic direction, such as initial procurement targets across a two- to five-year timeline, to allow industry to adapt and respond.

Q15. What aspects of the wider CM framework, auction design and parameters should we consider reviewing to ensure there are no barriers to success for introducing minima into the CM?

As discussed above, the Capacity Market has become an increasingly complex market to participate in. The potential introduction of minima to the auction risks further increasing the complexity and administrative burden of participation, which might lead to a reduction in assets taking part.

Furthermore, including the initial REMA consultation, this is the fifth consultation on the topic of CM reform that we have responded to in the last two years. Many proposals have been introduced in those consultations which have not been addressed in this one, and could have important implications for the success of introducing minima into the CM. REMA represents an opportunity to holistically review and reform the functionality of the CM, which has been missed. There is a risk of focusing too much on the introduction of minima into the auction process to the detriment of implementing other, potentially more impactful, reforms to support the decarbonisation and successful functioning of the CM into the 2030s and beyond.

To this end, the following aspects of the wider CM framework, auction design and parameters should continue to be reviewed as part of the REMA reform process, many of which have been identified in previous consultations.

> **Recommendation:** Ensure CM reform as part of REMA takes a holistic view of the mechanism and recognises the importance of other reforms. Publish responses to the government's Phase 2 proposals and 10-year review, and Ofgem's Ten-year Review of the Capacity Market Rules, and provide guidance as to how next steps following these consultations will complement the REMA process.

Definition of system stress events and the role of de-rating factors

In our response to the initial REMA consultation, we highlighted that, while capacity adequacy is important, a focus only on capacity is a reflection of traditional energy security thinking, based on maintaining a certain capacity margin in order to meet a predicted winter peak evening demand. That thinking is, in turn, based on the logic that, provided there was some capacity headroom against the winter peak, other aspects of energy system resilience could be managed by the System Operator. The definition of a CM system stress event – four-hour duration with sufficient pre-warning for the system operator to issue a CM Notice at least four hours in advance to mobilise large generation capacity – reflects this thinking.

We are pleased that the government has recognised this and is exploring the changing nature of future stress events and potential alternative approaches and metrics to the current standard.

Furthermore, any reforms to the reliability standard should also provide a more holistic review of the de-rating methodology, as highlighted in the supporting documentation:

"As de-rating factors are designed to reflect the definition of a system stress event within the current design of the CM, the changing nature of system stress events could raise more fundamental questions for the role of, and determination of, de-rating factors. For example, a de-rating factor that reflects the capacity to respond at times of peak demand will not appropriately reflect the capability of the same capacity to respond to sustained periods of low renewables output." [5]

Batteries are among the highest providers of new build capacity bidding into the CM auctions. However, the de-rating factors for batteries in both the T-1 and T-4 auctions have dropped in recent years. We feel that the current de-rating factor methodology, last updated in 2017, is no longer fit for purpose. If the status quo is maintained and the de-rating factors go down further in subsequent auction rounds, battery storage developers will not bid in the auction rounds due to a lack of revenue versus the costs/penalties/risks.

While we welcome the review of the storage de-rating factor methodology currently being consulted on by the ESO, a more holistic review of the appropriateness and methodology of de-rating factors must be undertaken within the context of wider CM reform, to ensure that they are not detrimental to the government's decarbonisation aims. As such, we look forward to seeing the output of the government's research project to explore whether Loss of Load Expectation (LOLE) remains an appropriate measure and needs updating, as well as potential alternative metrics and encourage the government to include a review of de-rating factors as part of this.

> **Recommendation:** The government should undertake a holistic review of the appropriateness and methodology of de-rating factors as part of their programme reviewing the future of system stress events.

Extended performance testing

The extended performance test (EPT) only applies to storage CMUs and has to be undertaken every three years, unfairly penalising and adding costs to these projects looking to enter the CM. While we recognise that the CM should be a technology-neutral mechanism, when comparing the expectations

[5] Baringa Partners, Alternative Capacity Market Auction Designs, July 2023.

placed upon different technologies, it becomes apparent that the EPT process treats storage CMUs differently from other technologies, going against the technology neutrality principles of the mechanism. One member explained this during our workshop:

“On the legal risk and application to other technologies that compete in the CM, it’s interesting to note [that] the de-rating factor for storage is reduced significantly. The 2023 T-1 de-rating factors for offshore wind and [a] 1hr duration storage CMU are almost identical – 11.52% and 11.34%, respectively. The EPT is also a test of the ability to get close to or very near to the connection capacity, and with a 100 MW 1hr storage CMU versus 100 MW offshore wind, the battery would be required to get to 95 MW for an hour, whereas the offshore wind would only be required to get to 11 MW.”

This highlights the disparity between what is expected of storage CMUs in comparison to other technologies – as currently defined, the EPT requires storage providers to reach c. 95% of their connection capacity, which is a requirement that other capacity providers do not have. Furthermore, no equivalent mechanism exists for testing the durability of other technologies participating in the CM – in the above analogy, offshore wind would not be expected to prove it could deliver capacity for an extended period of time, nor would it incur penalties for missing said capacity by a MW. Meanwhile, if a storage CMU were to fail an EPT marginally (e.g. by 3%) they could potentially receive an intend-to-terminate notice.

As such, ESN members have repeatedly raised a concern that the current rules on extended performance testing need reviewing, as reflected both in our responses to the January and December 2023 consultations, and in subsequent engagement with the DESNZ team. There is a need to address a wider challenge of how to ensure reliable delivery of capacity across all technologies, rather than simply asking the question of how EPT can be optimised for storage CMUs.

For example, some older gas-fired generators might not be able to reliably deliver for more than 30 minutes, but currently no mechanism exists to test this technology’s durability or penalise the CMU for non-delivery. Therefore, if the government considers assurance of durability to be a priority, then there should be an exploration of whether EPTs should be introduced for all technologies.

> **Recommendation:** Review the requirements for an extended performance test, including whether an equivalent mechanism should be introduced for all technologies participating in the CM. If continued, reduce the frequency of EPTs in the CM for storage CMUs.

Battery degradation

The current process and systems in place to apply for CM contracts do not consider the technology characteristics of the current dominant energy storage technology, Li-Ion batteries. This technology has a degradation rate that is well known and understood. Providers limit the number of cycles they do per day to maintain the health of the battery cells and to stay within their warranty guidelines. In the T-4 auction, a 15-year contract is available and a battery storage project will degrade by a certain percentage rate over that time (depending on various operational factors). This means that, if they submit any bids using their full capacity, they will not be able to meet that requirement over the 15-year contract.

The alternative to this is to submit less than the stated connection capacity at the pre-qualification stage informally, which is not an ideal process and could be improved – we have seen many CMUs bidding with a capacity that is lower than the actual to include the assumed degradation over the length of the contract. This is counterproductive for developers and the bodies involved and limits the potential for this technology to contribute to capacity adequacy to the best of its ability.

It is also a compromise for asset owners who are limiting the commercial potential of their asset, with this reduction of revenue potential often priced into the business case in the form of higher clearing prices, driving up prices for consumers. In the last five T-4 auctions, the clearing price has consistently increased. While it is difficult to say whether this is a direct result of the treatment of storage CMUs, several of our members have pointed to a potential correlation between storage de-rating and rising prices. Furthermore, higher de-rating factors mean more nominal capacity needs to be contracted, which can also drive up marginal price.

However, some members have suggested that if the need for storage CMUs to self-derate was removed and the true available capacity was recognised, then they might be able to bid into the auction at lower prices for the same asset. This is due to the ability to provide more capacity to the system with the same asset, reducing the cost to consumers.

While we are aware of concerns around the need for the CM to remain technology-neutral, it should be possible to introduce a mechanism that recognises degradation curves for storage CMUs and applies across all technologies. For example, all technologies could be expected to provide a capacity profile for the contract duration, which could be flat for some technologies and represent a curve for others. It could also be flexible to allow all technologies to update this and redeclare their capacity annually, for example.

This would address the fact that storage CMUs are currently being treated differently when it comes to de-rating, accepting the uniqueness of storage CMUs in certain respects and allowing them to compete while still adhering to tech neutrality.

We raised this in our response to the January consultation, with a recommendation that storage CMUs should have the ability to provide an expected capacity curve for the 15-year contract period that could be re-assessed at intervals (e.g. annually) to update with the actual level of degradation.

We believe that this recommendation should continue to be considered by the DESNZ team, as the ability of the CM to better recognise the degradation of technologies over time would allow for both a) improved visibility of future capacity adequacy and, therefore, allow for more accurate auctions to procure additional capacity, and b) better cost reflectivity and, by extension, better value for consumers.

> **Recommendation:** Explore the development of a mechanism that could be applied across all technologies to allow CMUs to provide an expected capacity curve for the 15-year contract period that could be re-assessed at intervals (e.g. annually) to update with the actual level of degradation.

Market coordination and access

The consultation proposes to align 'longer-term' ancillary service contracts associated with CM/CfD contracts. In addition to the need for greater strategic direction to support investment decision making, we support increased coordination of price signals for the same reason. If the ESO continues to tender for long-term stability service contracts, there is a risk that separate tenders will not attract the most efficient investment in assets that provide both firm power and stability services. Investors may receive conflicting investment signals, and revenues from more efficient resources may be cannibalised by more expensive short-term solutions.

> **Recommendation:** The ESO/NESO should continue to improve coordination across markets to ensure assets are able to respond in a manner that benefits the system.

Furthermore, as we highlighted in our response[6] to the January long-duration energy storage (LDES) consultation, there is a risk that, without further market signals, the intended flexibility from long-duration assets supported via the bespoke mechanism will not be available to the system when required. There is currently no market signal for the operational assets that the cap and floor will support dispatching and helping the system in a longer-term stress event that we will likely see in the 2030s. For example, ahead of a shortfall of energy in an extended low wind event, LDES would need to import energy to be full and ready to dispatch over the period. We support further investigation of a proposed Storage Level Signal (SLS) or similar mechanism, in addition to a cap and floor, to incentivise the operation of assets to meet systems needs highlighted in the Carbon Trust report to the government.[7] As we put in our LDES consultation response, we believe a technology-agnostic approach to the LDES cap and floor focused on system needs is more appropriate. We would assume that any SLS design would emulate that approach. This requires further details of what that signal would look like and how it might interact with CM and other signals. Overall, this highlights the need for clear and

[6] Regen, 2024 Consultation response: Long duration energy storage cap and floor scheme.

[7] DESNZ, 2024 Report on the Role of Ancillary Services to Encourage Low Carbon Operability

coordinated market signals across a variety of mechanisms to support further low-carbon flexibility and LDES development.

Finally, the government's Phase 2 proposals also included the possibility of introducing additional technology classes for Demand Side Response (DSR) – the integration of flexible distributed energy resources into the CM and other electricity markets has significant potential, but there is much coordination and market design work to be done before the benefits can be realised.

> **Recommendation:** DESNZ to investigate a new Storage Level Signal in addition to a cap and floor to encourage the right operational behaviour of LDES once deployed.

Co-location

More could be done to encourage the participation of co-located sites in the CM. We define co-location as when energy storage is sited with generation (normally solar PV) and/or demand, and a shared grid connection exists. This is also known as a hybrid site or a multi-unit site. While we understand there have been some negotiations to allow co-located sites to pre-qualify and win contracts in the CM, the process of engaging the EMR delivery body for each site is inefficient. This needs reform to help improve the integration of this type of site into the CM. There were also discussions regarding the creation of a hybrid CMUs category in the CM open letter from BEIS in 2020.[8] As the number of co-located sites grows at the distribution and transmission network scale, this is something that we would like to see explored in more detail.

> **Recommendation:** Provide an optimised process for co-located battery storage sites to participate in CM via a new generating technology class and consultation process.

Overarching governance

As a more general point, if REMA leads to the government confirming the CM is the primary mechanism for ensuring capacity adequacy, then there is a need to simplify the governance and change-management process, which is currently slow and complex. The Capacity Market Advisory Group (CMAG) can provide recommendations which then require coordination between Ofgem and the government to enact. There is an opportunity to reform the governance process to make it simpler and fit for the future.

[8] BEIS, 2020 https://www.gov.uk/government/consultations/capacity-market-new-technologies-2020/open-letter-on-new-technologies-in-the-capacity-market#fn:2

> **Recommendation:** As part of holistic reforms to the CM, the government and Ofgem to review and seek to simplify the governance of the mechanism.

Q16. Do you agree with the proposal that new lower-emission limits for new build and refurbishing CMUs on long-term contracts should be implemented from the 2026 auctions at the earliest?

As we raised in our response to the March 2023 consultation, we are pleased to see that the government recognises that the Capacity Market as it is currently designed is inconsistent with net zero and aims to align the current rules on emissions limits with net zero targets. While we do not support measures which delay CM alignment with net zero, we understand that the 2024 implementation of lower emission limits is not feasible at current timelines. The government should ensure that action is taken immediately to ensure that the rule changes can be implemented in time for pre-qualification in 2025 to avoid further delays, which could impact investment in low-carbon flexibility assets. Furthermore, policymaking needs to be clear and consistent to allow certainty for participants to be able to plan and respond accordingly. When commitments are amended or delayed at short notice, this creates unnecessary uncertainty, which ultimately drives costs up for the end consumer and delays the net zero transition.

In addition to this, further clarity is required on the emissions limits due to be implemented – the proposed changes to emissions limits in the March 2023 consultation did not go far enough in preparing the CM for a net zero future or in properly valuing the emissions avoided by the participation of low-carbon assets in the CM. For example, we raised a concern that continuing to allow fossil fuel generators to meet a yearly emissions limit, even after the intensity emission limit is tightened after 2034, risks creating a situation where unabated gas assets continue to participate in the CM. This is because, even if an unabated asset does not meet the intensity emission limit, it could still generate annually for a percentage of time to meet the yearly limit. By continuing to provide contracts under this principle, the financial incentive of participation might be greater than any penalties incurred for breaching the yearly emission limit, incentivising them to maximise their output to maximise revenues regardless of any emissions limit.

> **Recommendation:** Provide clarity as soon as possible on emissions limits proposals and the implementation pathway of this in the CM.

Q17. If you are considering investment in flexible capacity, to what extent would emissions limits for new build and refurbishing capacity impact your investment decisions?

Our members are supportive of the introduction of emissions limits. However, there are also more fundamental investment challenges for battery storage that need to be addressed, as highlighted in our response to Q15.

Q18. Considering the policies listed above, which are already in place or development, what do you foresee as the main remaining challenges in converting existing unabated gas plants to low-carbon alternatives?

As the consultation states, several policy mechanisms are currently in development intended to support the shift to low-carbon dispatchable power, such as the Dispatchable Power Agreement (DPA) to incentivise CCUS. However, while the building blocks are being developed to allow unabated gas plants to convert, challenges remain. H2P and CCUS do offer promising solutions, but they are still far off the needed level of commercialisation to support near-term conversion. Furthermore, while recent policy developments are starting to provide some clarity, far more certainty is required before CM participants can make firm investment decisions based on a reliable, cost-effective and sufficient hydrogen supply.

The government's priority should be the continued development of clear, coordinated policy to support the commercialisation of emerging technologies, including more strategic direction regarding how different technologies such as H2P, LDES and CCUS will be working to support a net-zero system. An overall strategy needs to be communicated to the industry to provide confidence in the approach and, as such, we suggest the government develops an updated flexibility and storage strategy, including an update to the 2021 Smart Systems and Flexibility Plan.

> **Recommendation:** DESNZ should continue to prioritise the development of clear, coordinated policy to support the commercialisation of CCUS and H2P, as well as providing a clear overall strategy for the role and scope of low-carbon dispatchable power in the future energy system, including LDES.

Furthermore, while support mechanisms for transitioning to low-carbon technologies are vital, the CM continues to send a strong signal supporting investment in new unabated gas generation, to the detriment of commercially well-established low-carbon technologies such as battery storage. The government states, *"We also expect that carbon pricing through the Emissions Trading Scheme (ETS) and Carbon Price Support (CPS) will play a role in incentivising and increasing the competitiveness of alternatives to unabated gas."* However, it is notable that the GB Emissions Trading Scheme (ETS) has fallen significantly below the equivalent EU ETS and may not be compatible with the UK's net zero targets. We welcome the proposal from the government to reduce the UK ETS cap to bring carbon prices in line with net zero targets, smooth the transition to higher carbon prices over time,[9] and highlight the importance of properly functioning carbon pricing in supporting the transition.

[9] DESNZ, 2024 https://assets.publishing.service.gov.uk/media/649eb7aa06179b000c3f7608/uk-emissions-trading-scheme-consultation-government-response.pdf

As a part of this, Regen and the ESN have been raising the issue of accounting for carbon in operational signals for several years (e.g. see our position paper[10] published in 2020). It is an area on which we have engaged closely with National Grid ESO on through the ESN's Markets and Revenues Working Group. It is imperative to have a better carbon valuation across all electricity markets, including clear carbon reporting on all markets and services. We welcome the data being provided by the ESO from the Balancing Mechanism and the new methodology for carbon reporting of DSO services. However, we would welcome further ESO actions to monitor the carbon intensity of the services and markets they deliver. We have been working with the ESO on how the new NESO could work more effectively in driving net-zero delivery. Better monitoring and reporting of the carbon intensity of different markets, such as the CM, would highlight the extent to which the current structure renders it incompatible with decarbonisation targets, strengthening the case for reform.

Finally, we are concerned by the intention to incentivise additional investment in unabated gas when low-carbon flexible technologies can be built by the early 2030s, and the potential unintended consequences. Competition from unabated gas plants with CM contracts, even for limited running hours, could negatively impact investment in low-carbon alternatives. Policies to encourage new-build unabated gas could have the perverse effect of chilling investment in the very low-carbon flexible technologies that the government seeks to encourage and could lead to stranded assets – in contradiction of the REMA assessment criteria of delivering value for money for consumers.

> **Recommendation:** Give NESO the mandate to monitor carbon intensity and prioritise low-carbon assets in market services, such as the CM. Continue to strengthen the UK ETS to provide a stronger decarbonisation signal.

Q19. Do you think there is currently a viable investment landscape for unabated gas generation to later convert to low-carbon alternatives? If not, please set out what further measures would be needed.

See answer to Question 18.

Q20. Do you agree that an Optimised CM and the work set out in Appendix 3 will sufficiently incentivise the deployment and utilisation of distributed low-carbon flexibility? If not, please set out what further measures would be needed.

The work set out in Appendix 3 was a helpful summary of many of the key challenges that our members have identified, and many of the mechanisms listed to improve operationality for distributed low-carbon flexibility should continue to be explored, such as addressing skip rates in the BM, improving standardisation for revenue stacking and lowering the participation threshold to include smaller providers in the market.

[10] Regen, 2020 https://www.regen.co.uk/building-flexibility-markets-for-a-net-zero-electricity-system/

However, as identified in our response to Q15, there is much coordination and market design work to be done before the benefits of DSR and distributed flexibility can be realised and, as discussed in our response to Q3, within REMA, there has been limited focus on consumer engagement and encouraging their participation in demand-side flexibility provision. We were pleased to see the focus on market-wide half-hourly settlement in the government's response to the more innovative energy retail market Call for Evidence and highlight the importance of unlocking distributed flexibility. We urge the government to continue to enact retail and wholesale market reforms in tandem, to maintain alignment across energy market frameworks and to ensure that consumers are able to benefit from a decarbonised electricity system in a just and fair manner.

> **Recommendation:** Continue to explore retail and wholesale market reforms in tandem to ensure that consumers are able to benefit from a decarbonised electricity system in a just and fair manner.

Finally, the underlying issue of grid connections still needs to be addressed. The inability to secure grid connections in a reasonable timeframe and at an acceptable cost is significantly impeding the deployment of grid-scale electricity storage. It will be important to coordinate market-based measures with ongoing improvements to grid connections that are starting to occur at the transmission and distribution level. There is a considerable amount of uncertainty in the industry caused by these ongoing connection reforms and a shift towards a first-ready, first-connected approach to queue management (alongside TMO4+, technical limit offers, etc). Any market reforms, such as to the CM, are not going to be successful in driving the growth of distributed flexibility without more reforms to the grid connection process, which remains the main barrier to deployment for the sector as it stands.

> **Recommendation:** Market reforms must align with, and take into account, grid connection reforms.

Q21. Do you agree that our combined proposed package of reforms (bespoke mechanisms for certain low-carbon flexible technologies, sharper operational signals, and an Optimised Capacity Market) is sufficient to incentivise flexibility in the long-term? Please set out any other necessary measures.

Please see response to Q15, exploring additional reforms that are required as part of the CM.

More broadly, as discussed in our response to Q14, without a clear set of definitions and principles around the optimum use of minima within the CM, it is challenging to identify unintended consequences of such an approach at this stage.

As the reform process continues, it is important that the government continues to take a holistic approach and ensure that measures set out in the REMA consultation align with existing policy and policy being developed outside of this consultation. CM reform in and of itself is unlikely to bring about the significant levels of flexibility required to realise a decarbonised electricity system, without strengthened and coordinated price signals, as well as bespoke mechanisms to support developing technologies, such as LDES. We therefore agree with the approach to progress with the design of bespoke market arrangements for certain low-carbon flexible technologies on a separate timeline to the REMA process and refer to our response to the LDES cap and floor scheme for more details.[11]

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

Responses to questions 22-24

Q22. Do you agree with the key design choices we have identified in the consultation and in Appendix 4 for zonal pricing? Please detail any missing design considerations.

From our engagement with our members in the GB electricity storage industry so far, there is not a consensus in support of a shift to zonal wholesale market system. The industry is keen to see a detailed design for a zonal market in GB in order to be able to fully assess the potential impacts. However, as it stands there is not enough information on the mechanics of how a zonal market would work in the GB market. The opportunity for more price volatility/spreads and revenues from wholesale market in a zonal market has to be assessed against the wider risks and significant changes needed to deliver it, including but not limited to an increase in the cost of capital, move to central dispatch, moving all assets to non-firm transmission network access (with a new Financial Transmission Rights market) and a complete reform of the Balancing Mechanism and ancillary services. For grid-scale battery storage sites this will significantly impact business models and increase uncertainty.

Lack of details on zonal design - There is a lack of information on what a zonal wholesale market model would look like in GB. Key decisions such as the number and location of zones, as well as the frequency of zone review, would fundamentally change the market design. Industry understands that more work is being conducted by the REMA team to develop the zonal pricing option. However, it is currently extremely difficult to assess the impact of zonal pricing, or even judge how such a market design would be implemented within the context of the current GB market and net zero transition.

Every aspect of the zonal design requires more detail, but especially:

- The definition of zones and how zones might change over time.
- Dispatch arrangements and whether zonal would include a shift to central dispatch.
- Demand exposure to zonal price signals and how this would be implemented in retail markets.

[11] ESN, 2024 https://www.regen.co.uk/consultation-response-long-duration-energy-storage-cap-and-floor-scheme/

- The distributional impacts of zonal pricing and its fairness between zones and between consumer groups within zones.
- Arrangements for forward trading, Financial Transmission Rights (FTR), markets and hedging.
- Zonal impacts on CfD design including reference price, negative price rules and alignment with CfD REMA design options including deeming.
- Zonal impacts on network charging and the ongoing reforms to both the Transmission Network Use of System (TNUoS) and Distributed Use of System (DUoS) charges.
- Zonal impacts on current ancillary markets, including for dynamic frequency response services, reserve services and the Balancing Mechanism.
- All aspects of how zonal pricing would impact distribution-connected assets and consumers.
- Interaction and integration with EU markets and interconnection.

We understand that the next step following this consultation period will be a response in summer 2024, and there is an aim to publish final decisions and a full impact assessment in mid-2025. We would like to see an additional consultation step included ahead of any final decisions from government, as so far there has been a lack of detail communicated on the zonal market design.

> **Recommendation:** DESNZ to provide industry more details on the proposed design of a zonal market in GB to make an informed decision. We would like to see an additional consultation step with further details shared with industry, ahead of any final options being produced in mid-2025.

In the following section we outline some wider concerns on the implementation of a zonal market in GB and some additional design considerations for discussion.

Transmission focused assessments and bias – The current discussion and zonal market design are overwhelmingly focused on helping to resolve transmission constraints and transmission-connected assets. There has been limited discussion on the impacts of a zonal market on embedded/distribution-connected assets, which are a large proportion of the existing renewable energy and electricity storage projects on the system.

> **Recommendation:** DESNZ to provide a wider assessment of the impacts of shifting to a zonal market in further analysis and publications, including embedded/distribution-connected assets.

Intra-zonal mechanisms – There has been discussion on the inter-zonal rights and access mechanism, but a further point that has not been part of the design options discussion so far is the impact of the zonal design on transmission and distribution system within the zone, intra-zonal. What access rights do assets have intra-zonal? How are transmission and distribution constraints managed within zones? Depending on where zones are located, there could be unintended consequences and additional challenges created on the electricity network. These intra-zonal impact assessments should be included in any further detailed work on the zonal market design.

> **Recommendation:** DESNZ to include further analysis of intra-zonal impacts of a zonal wholesale market design.

Costs of grandfathering – A zonal market is assumed to have market/grid access that is non-firm, meaning a market participant only has a right to access the market and dispatch when instructed to do so by the market operator. In theory, no constraint payments are made to the generator. In practise, existing transmission rights holders are likely to be compensated in some way as they have built their project on an assumption of firm access to the transmission network. A new market for Financial Transmission Rights (FTRs) is proposed but is highly uncertain. As well as network access rights, the existing revenue support mechanisms (e.g. CfDs) would have to be grandfathered.

The report on the System Benefits from Efficient Locational Signals published alongside the consultation from LCP Delta and Grant Thornton, states that, 'an assessment of grandfathering costs is out of scope of this study'.[12] Grandfathering costs are likely to be significant, and we believe this should be clearly communicated and understood before any further consultation on a zonal market. We recommend that an assessment on grandfathering costs be done if it has not been done so already, to accurately reflect the costs of shifting to a zonal market model.

> **Recommendation:** DESNZ to complete and share further analysis on the grandfathering costs of shifting to a zonal wholesale market.

Cost of capital – We are pleased to see more focus on the impacts of zonal (and the wider set of reforms) on the cost of capital coming through in the second REMA consultation and in the accompanying reports. This is a critical factor in any radical market reform decision, and we are already hearing from members that there is a risk premium driven by the current uncertainty in the reform options for the GB market. Audience feedback at Regen's REMA engagement session on 22 April confirmed that there have already been impacts on investor confidence (see Figure 2).

[12] LCP Delta & Grant Thornton, 2024 https://assets.publishing.service.gov.uk/media/65e3a3dc3f69450263035fc3/9-system-benefits-from-efficient-locational-signals.pdf

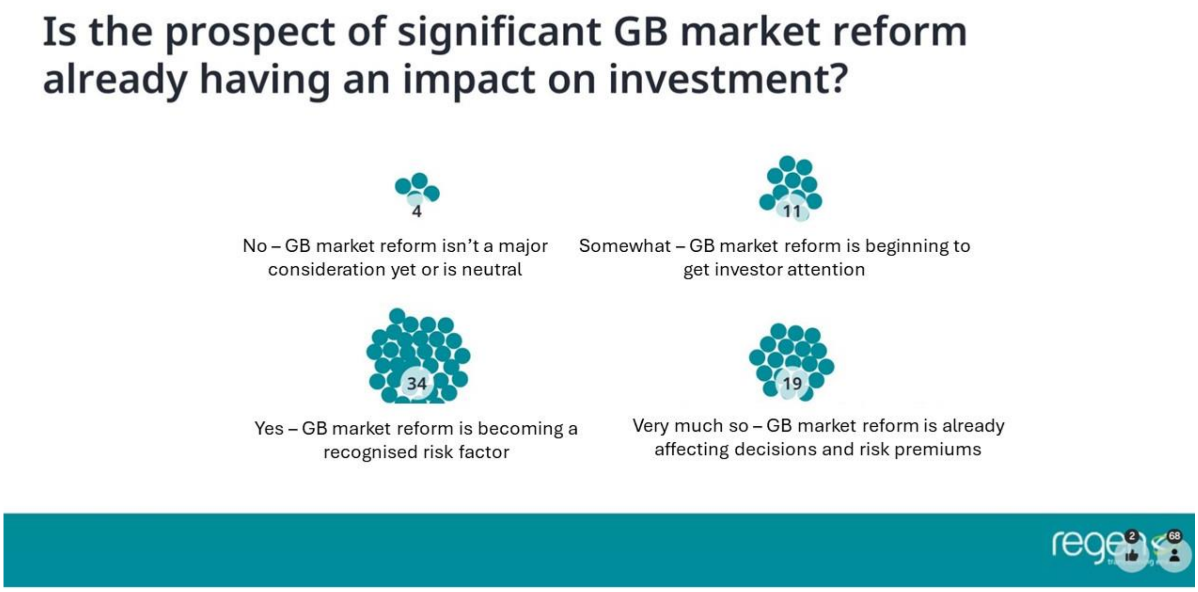

Figure 2: Participant responses on the prospect of significant GB market reform and its impact on investment. Source: Regen REMA consultation event 22 April 2024.

This message aligns with other industry surveys and some of the feedback in the first REMA consultation response summaries.

The cost of capital is important, but is not the only risk as a focus on capital cost assumes that investors can price the future zonal market. This may be impossible, in which case we could also see a stall in investment and delay in project development.

There are also ongoing risks associated with a zonal market arrangement where market participants lose access rights and are reliant on central dispatch. Evidence of this risk is that most examples in international markets are supported by a form of financial hedging via an FTR market or other financial contracts. However, hedging is expensive, and this additional system cost should be considered part of the overall cost-benefit analysis. Hedging is also imperfect. It is difficult to secure long-term FTRs, and the availability of FTRs may be limited in a high-renewable energy system.

Many members were keen to stress that the challenge we now have is that the macroeconomic environment has shifted significantly since the REMA reform process started. We have entered a period of higher interest rates, which has changed the availability of capital. This means that project finance has become more challenging to raise and that the investment community has looked to other investments and jurisdictions for reasonable returns (e.g. US or Italy).

> **Recommendation:** DESNZ to continue to assess the implications of any policy changes on the cost of capital, taking into account the more challenging macroeconomic environment, and make sure this is a high priority in any further work or final options assessment.

> **Recommendation:** DESNZ must also consider other risk factors that investors are unable to price future zonal prices resulting in project delay and the ongoing commercial and hedging risk associated with operating in a more volatile market with zones.

Regarding the specific points in the Appendix 4 design options:

- Central versus self-dispatch – From our engagement with members, there is a consensus against central dispatch as an option with assets retaining the current arrangements of mainly self-dispatch, alongside a set of wider incremental reforms in the settlement period, ancillary markets and the Balancing Mechanism. The lack of transparency and clarity on the BM dispatch decision making by ESO has been mentioned as a key reason why the industry is not in support of central dispatch. Overall, we believe the operator/optimiser is best placed to dispatch electricity storage to meet system needs when the right price signals are provided. They have the expertise and software capabilities that are able to understand and adapt the dispatch behaviour to match the capabilities of the storage technology and owner requirements (e.g. management of warranties). We do not believe that a centralised dispatch is a good option for the GB market and that much of the current challenges outlined in the case for change can be solved from progressive incremental reforms and in some cases are already happening (e.g. co-optimisation).

- Demand-side exposure and consumer impacts – If there is shift to zonal, we would recommend this only extends down to commercial and industrial consumers and be phased over time. We believe there is a clear link between those in fuel poverty and less flexible demand (see wider calls for a social tariff). Providing exposure to the domestic consumer level would exacerbate this problem and increase inequality. Our impression is that very little design work has so far been conducted to look at the demand-side exposure of zonal pricing, or the extent to which demand customers would be directly exposed to zonal price signals. This is an extremely complex and critical area that has a high degree of overlap with retail market reform and the role of energy supply/retail.

  > **Recommendation:** DESNZ should accelerate ongoing work to determine the degree to which demand should be exposed to zonal price signals, including an analysis of distributional impacts and questions around the fairness of using the wholesale price to give constraint management signals.

- Market power and gaming mitigations **–** The market power of assets will shift considerably under a zonal wholesale market. There are real concerns that CfD and cap and floor (interconnectors and LDES in the future) supported assets may have the potential to game the zone and cause significant impacts on wider assets in that zone. In addition, larger assets in a zone, such as a CCGT, would have increased market power in a zonal system. These changes are all likely to need more monitoring resources from Ofgem and/or ESO. The additional costs of this should be taken into account in any assessment of zonal options.

> **Recommendation:** Maintain the current approach to market monitoring from Ofgem and ESO, with an increase in resourcing and actions on parties that are not following rules/licence obligations.

- Access rights and hedging – There is concern within the industry that the costs and risks associated with removing firm access rights and setting up a new FTR market have not been fully assessed. We mentioned above that this will impact the cost of capital. Access rights are particularly important to grid-scale electricity storage, as many assets are providing services to the ESO to help maintain energy system security and the removal of firm access rights will impact that provision and wider business model. In addition, this proposed shift in access rights is happening during radical change and connection reform at the distribution and transmission level. This makes the connection costs and value of projects very difficult to assess, and the uncertainty regarding grid connection reforms is already undermining investment decisions.

> **Recommendation:** DESNZ to provide more specific analysis on the costs of setting up a FTR market in GB and how this would work in practise.

Q23. How far would our retained alternatives to locational pricing options go towards resolving the challenges we have identified, compared with locational pricing? Please provide supporting evidence and consider how these alternative options could work together, and/or alongside other options for improving temporal signals and balancing and ancillary services.

Since the start of the REMA process, several significant system planning initiatives have been put in place that point to a new approach with a more integrated and strategic planning landscape that includes:

- A new national system planning framework that includes a Strategic Spatial Energy Plan (SSEP), Central Strategic Network Plan (CSNP) and new future energy pathways.

- New initiatives at a regional and local level to develop Regional Energy Strategic Planners (RESP) and to roll out local area energy plans.

The development of integrated plans that span national and regional boundaries, energy vectors and the alignment of energy assets and infrastructure could provide the locational signals that have been missing in the current market, speeding up planning decisions and adding to investor confidence. If implemented effectively alongside wider planning, network charging reforms and new constraint services, these changes could provide a set of locational siting signals that are far more effective than a zonal wholesale market signal.

For grid-scale storage, there is a wider need that we have already outlined for a specific target to be developed with NESO and the industry. As in this more centralised and strategic energy system planning approach, targets are used as the basis for analysis and become more important.

> **Recommendation:** The government should set an overall target for grid-scale electricity storage capacity for 2035 in collaboration with NESO and industry that feeds into the Strategic Spatial Energy Plan.

Option A: Using Ofgem's pre-existing network charging reform programme (TNUoS and DUoS)

ESN welcomes the strategic review of TNUoS, the TNUoS taskforce and the new storage TNUoS subgroup. The latter is particularly appreciated, and we have been ensuring members are aware and engaged in that process. We expect that this process will provide Ofgem and the industry with a clear view of the future of TNUoS reforms for storage and a set of recommendations following the three-month process.

Several ongoing modifications could significantly impact the methodology used to assess TNUoS for storage, such as CMP393[13] (proposed by Zenobe Energy) and CMP405[14] (proposed by SSE). We understand that these modifications and others will continue in parallel while the storage TNUoS subgroup is developed and delivered over time.

We have been hearing concerns about the treatment of grid-scale electricity storage from various members, and we would like to see TNUoS charged in a way that is more reflective of its impacts on the system and with more accurate and predictable long-term forecasts.

[13] ESO, 2024 https://www.nationalgrideso.com/industry-information/codes/cusc/modifications/cmp393-using-imports-and-exports-calculate-annual-load-factor-electricity-storage

[14] ESO, 2024 https://www.nationalgrideso.com/industry-information/codes/cusc/modifications/cmp405-tnuos-locational-demand-signals-storage

ESN supports the alignment of timeframes between the REMA process and the wider TNUoS network charging reforms and welcomes the launch of the new storage TNUoS subgroup.

Regarding DUoS, we are keen to see further reforms through the Charging Futures forum and wider code modification processes. In general, there is considerable volatility in DUoS charges for storage at Extra High Voltage, providing considerable uncertainty for projects being developed. We have recently been made aware of a specific issue and classification of the High Voltage level of the import capacity charges by a member that we will investigate further.

Option B: Reviewing Ofgem's transmission network access arrangements

ESN does not support a shift to non-firm access arrangements for all existing and new assets. This would undermine business models and investment in the GB sector at a crucial time for the deployment of grid-scale storage. Access to the network is crucial for grid-scale storage providers often provide critical services to maintain energy security. It would also send a bad signal to investors in these projects and potentially increase the cost of capital, generally reducing investor confidence in GB energy projects.

There could be a case for new assets being connected to be done on a non-firm basis with transparency to the market on the implications of this for ancillary service provision and wider revenue opportunities clear upfront. This would need to be done over time and in alignment with the ongoing grid connection reforms. Overall, members are already dealing with significant delays from network operators and a large amount of grid connection/queue management reforms. Trust in the network operator's ability to deliver these reforms is low in the industry, and we feel that this change would further undermine confidence.

As mentioned earlier, the industry would like further information on the wider impacts on new and existing distribution connections from a shift to non-firm transmission access rights and introducing a zonal wholesale market.

Option C: Expanding measures for constraint management

ESN is very supportive of the development of new constraint management services. Regen[15] and others[16] who have looked at the issue of constraint costs have identified many reforms, process improvements and market developments that could reduce (but not eliminate) the occurrence of constraints and the cost of constraint management. Many of these ideas and proposals are already in

[15] Examples of previous Regen studies in this areas include Regen - Seven Solutions to reduce Constraint Management Costs and evidence given to the ESNZ Select Committee

[16] See for example analysis by Dr Simon Gill Simon Gill - Exploring options for constraint management in the GB electricity system and by Frontier Economics Reform options for electricity balancing arrangements in Great Britain

progress as part of innovation projects or within the constraint management and new market initiatives being rolled out by the ESO.

One recent example is the current ESO Thermal Constraints Collaboration Project which has produced over 30 responses and has focused on those that are market-based solutions (see Figure 3). Several of these responses, including enhanced inter-trip and grid booster ideas, aim to enhance the ability of the control room to increase and optimise grid capacity utilisation and manage variable generation without resorting to turn-down generation.

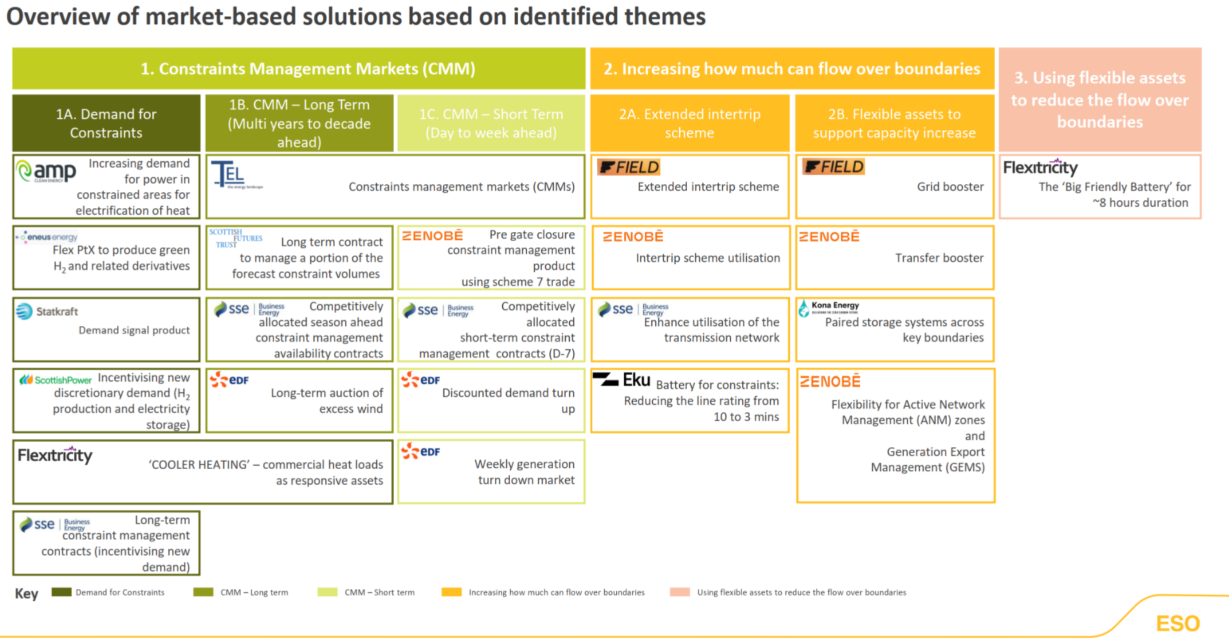

Figure 3: ESO Thermal Constraints Collaboration project – overview of solutions.

Several ESN members have put forward ideas to this process and engaged closely with developing new constraint services. The next stage is the shortlisting and then more detailed development of six options, alongside industry. We commend ESO on their approach to this project so far and look forward to seeing what services are taken forward and in what form. This project should continue to receive oversight from DESNZ and Ofgem to ensure that new market-based constraint management solutions are delivered rapidly to help reduce balancing costs sooner rather than later.

> **Recommendation:** ESO to continue to work with industry on the implementation of new market-based constraint services, with DESNZ and Ofgem oversight.

Option D: Optimising the use of cross-border interconnectors

One of the main reasons in the case for change in Challenge 4 is the inefficient dispatch of interconnectors. ESN understands that several interconnector dispatch reforms can be made through progressive incremental without a shift to a zonal wholesale market. This could include but is not limited to the points made in Table 1. A recent report by Frontier Economics for Scottish Power has also highlighted some of these solutions.[17] Taken together, these reforms could significantly reduce the interconnector dispatch challenges that the ESO is dealing with, and we recognise the need for an interconnector reform programme within the overall governance of REMA.

Table 1: Overview of potential interconnector reforms

Strategic planning and cross-border cooperation	• Develop a UK interconnector strategic plan aligned with the SSEP and CSNP. • A shift from developer-led to the strategic development of interconnectors. • Re-engage with EU (ENTSO-E) IC Offshore Network Development Plan and ACERS. • Build on bilateral collaboration e.g. GB Island of Ireland energy cooperation MOU.
Improve interconnector market efficiency	• Recouple with EU trading markets. • Align GB and interconnector trading timescales and markets. • Realign GB-ETS /EU-ETS carbon pricing. • Establish intraday trading across all interconnectors.
Manage interconnector flows and constraints	• Greater SO-SO collaboration and coordination. • Enhance and enable SO-SO counter trading. • Enhance and enable SO-market countertrading.

Option E: Introduce a locational element to the Capacity Market

ESN supports discounting locational elements in the Capacity Market and shifting to a low-carbon minima approach.

Option F: Introduce a locational element to the CfD

ESN supports the discount of the locational element in CfD.

[17] Frontier Economics, 2024. Reform options for electricity balancing arrangements in Great Britain.

Q24. Do you agree with our proposed steps for ensuring continued system operability as the electricity decarbonises? Please detail any alternative measures we should consider and evidence of likely impacts.

Shorter settlement periods

There was consensus among our membership supporting a shift to shorter settlement periods. The industry has been asking for reform to settlement periods for years, and we were happy to see this type of reform included in this second consultation. A move to a 15-minute period is a reasonable starting point. We believe that a further shift to a 5-minute settlement period could also be warranted in the near future.

> **Recommendation:** DESNZ to work with industry on the introduction of a shorter settlement period.

Gate closure

We were disappointed that gate closure shortening has been provisionally discounted in the short to medium term in the REMA process. The impact of shorter settlement periods will be significantly reduced if there aren't any corresponding gate closure reforms.

The point made in the consultation regarding shortening gate closure was of some concern – "could reduce the ESO's ability to balance the system efficiently and economically and may have security and safety implications". We understand that there would be signficant system and IT changes needed at ESO to deliver a shorter gate closure. However, we do not believe that security and safety implications should be used as a reason to delay this crucial type of reform.

> **Recommendation:** DESNZ to re-introduce gate closure shortening as an option in the REMA reform timescales.

Balancing Mechanism reforms

The ESN has been campaigning to remove barriers to the dispatch of storage and other assets in the BM for some time. See, for example, our letter to ESO in July last year,[18] referenced in the LCP Delta

[18] ESO, 2023 https://www.nationalgrideso.com/news/eso-responds-esn-call-balancing-mechanism-reforms

and Grant Thornton report alongside the consultation.[19] We welcome the mention of this as a crucial area of reform in the second REMA consultation and our engagement with ESO on this subject so far.

It is promising to see the ESO taking steps to address this, such as committing to increase participation in the BM and, as part of the Open Balancing Platform project,[20] deploying the Bulk Dispatch Optimiser in December of last year, which is an agile tool to allow control room send hundreds of instructions to smaller Balancing Mechanism Units (BMUs) and battery storage. A shift to the 30-minute rule has also started to make a meaningful impact on battery dispatch. Further stages are expected to be delivered over the next few years to integrate additional services into the Open Balancing Platform and BM dispatch process.

We also expect the delayed dispatch transparency methodology and retrospective assessment to be published in the next few weeks. This is a priority for the sector, and we look forward to engaging with the new approach moving forward.

These changes are starting to make a difference to the level of skipping of batteries in the BM,[21] and the most recent data for April 2024 shows considerable improvement, with some assessments showing a 100% increase in battery utilisation from December 2023 to April 2024. However, there is further work to harness the potential for low-carbon flexibility in the BM that remains dominated by large high-carbon assets. Further progress on this will deliver cost savings to consumers and lower carbon emissions.

> **Recommendation:** We ask that Ofgem continues to monitor progress and hold ESO to account on the pace of BM reforms, to allow storage BMUs to be able to meaningfully contribute to balancing actions and reduce the cost of managing constraints.

A further area of reform that is a key limiting factor in a wider role for storage in the BM is the development of a new set of dynamic parameters to more accurately inform the ESO control room of the availability of limited duration assets, such as battery storage. This work is now being delivered in Grid Code 0166 working group which has met three times.[22] We have appreciated the approach by ESO in trying to expedite this working group process, but delays in the timelines now seem inevitable due

[19] LCP Delta & Grant Thornton, 2024 https://assets.publishing.service.gov.uk/media/65e3a3dc3f69450263035fc3/9-system-benefits-from-efficient-locational-signals.pdf

[20] National Grid ESO, December 2023; First stages of Open Balancing Platform go live

[21] 'Skipping' can be defined as an asset not being accepted in the Balancing Mechanism despite offering a more attractive price to grid than the top price accepted for a settlement period (being in merit order).

[22] ESO, 2024 https://www.nationalgrideso.com/industry-information/codes/gc/modifications/gc0166-introducing-new-balancing-programme-parameters-limited-duration-assets

to a number of concerns raised. Implementation of the new parameters is now expected in spring 2025 and that will depend on the extent of the additional work needed within the working group.

> **Recommendation:** ESO to work with industry to continue to accelerate the timeframes of the implementation of new storage parameters in the BM for limited duration assets (Grid Code 0166).

ESO has admitted that battery storage assets have not been used for constraint management in the BM (system-flagged actions). This means that, for system-flagged actions, no matter how batteries are pricing themselves in BM bids and offers, they currently are not being dispatched and are limited to energy actions, representing only a small proportion of the actions taken in the BM. This is a significant limitation and means that on top of a high skip rate for energy actions, there is a 100% skip rate for system actions that are normally behind a transmission constraint (e.g. thermal or voltage). This challenge was highlighted in the LCP Delta and Grant Thornton report published alongside the second REMA consultation[23]. This has recently started to change with a small number of system-flagged actions being delivered by battery BMUs in recent weeks. Opening up more of these system-flagged actions to wider competition from low-carbon sources of flexibility would help to reduce balancing costs passed back to consumers and help to lower the carbon intensity of the BM.

> **Recommendation:** We ask that Ofgem directs ESO to review its rules as to which system actions storage BMUs can respond to, to improve the ability of storage BMUs to contribute to constraint management.

A storage operator won't necessarily know if they are submitting bids in the Balancing Mechanism at a time of transmission constraint due to a lack of clear market information.

There is some information already available. The ESO system flagged actions in the BM are an indicator of transmission constraints being active. A pattern of accepted system-flagged actions does indicate there is a constraint active of some kind. And in our members workshop on the TCLC in February 2024, Ofgem confirmed that identifying patterns where bids are being system flagged under specific system conditions and weather could allow asset owners to identify if they are behind a transmission constraint. However, this is not a clear form of assessment, and the lack of transparency increases risks for industry participants that they may fall foul of the Transmission Constraint Licence Condition.

[23] LCP Delta & Grant Thornton, 2024
https://assets.publishing.service.gov.uk/media/65e3a3dc3f69450263035fc3/9-system-benefits-from-efficient-locational-signals.pdf

It is arguable that there is at least some market information available on thermal constraints. However, voltage constraints are more opaque. ESO retains the key sources of information on this area and while there are moves to open this area up under new stability markets,[24] this area remains costly to consumers and is dominated by high-carbon assets on the system. The development of these new services and markets has been slow.

Network outages are another area of uncertainty. It may be clear if your own asset is impacted or if you are provided with a report by the Transmission Operator (TO) that there is an active transmission outage. However, it is likely that other market participants are not aware of this ahead of time to respond and price themselves in the BM accordingly. We also understand that some industry parties have a much better understanding of the network condition, such as nuclear power station operators, leading to a mismatch in the availability of information between different actors.

In addition, almost all of the above is likely to only be available retrospectively. It is not providing a clear market signal of a transmission constraint ahead of time to inform pricing in the BM and help industry participants align with the TCLC.

ESO has committed to providing a Centralised Strategic Network Plan (CSNP) as part of its transition to the National Energy System Operator, which will provide "the assessment of system requirements and will look further out, 10 years ahead".[25] There remains a lack of market information on constraints in the interim.

> **Recommendation:** We ask that Ofgem directs ESO to publish more datasets on transmission constraints, including thermal, voltage and stability, ahead of the CSNP. This should include detailed forecasts ahead of time to inform industry parties, leading to higher transparency.

The improvements in the BM made to date could be seen as the start of a more ambitious programme of reform and investment to create an advanced BM operated by the "Control Room of the Future"[26], which would be fully digitalised, highly automated and making use of the latest AI and digital twin technologies such as the virtual energy systems[27]. The Open Balancing Platform is a great new software tool for the control room to harness for BM dispatch. This transition away from legacy systems and focus on digitisation at ESO must continue at an accelerated pace to harness the low-carbon flexibility available, saving consumer costs and reducing carbon emissions.

[24] ESO, 2024 https://www.nationalgrideso.com/industry-information/balancing-services/stability-market

[25] ESO, 2024 https://www.nationalgrideso.com/document/299926/download

[26] ESO, 2024 https://www.nationalgrideso.com/what-we-do/electricity-national-control-centre/balancing-programme

[27] ESO, 2024 https://www.nationalgrideso.com/future-energy/virtual-energy-system

New constraint management services

See answer to Question 23 – Option C.

Central dispatch

The industry accepts the need for significant reforms and enhancements to the market and system operation processes. The basic building blocks of an efficient market are there, but the market and system operation are sometimes misaligned. It also lacks transparency, for participants and the system operator in key areas, such as in the Balancing Mechanism. There is a cross-industry consensus that market and operational systems, data and processes must be upgraded and further digitalised. However, as we outline in our answer to Question 22, there is no consensus for zonal pricing in the wholesale market within our membership nor a consensus against central dispatch. This is for a number of reasons, including but not limited to:

- The general view is that optimisers/operators are best placed to make decisions on the dispatch of assets in GB. The significant existing expertise in optimisers that manage assets across the wide-ranging number of revenue streams for grid-scale electricity storage is more appropriate.
- Co-optimisation, which is outlined in the consultation as a key benefit of a move to central dispatch, is already happening across ESO services and in bidding strategies under the Enduring Auction Capability. The new algorithm used has provided challenges for the industry, but is saving consumer costs and delivering benefits to the system.
- A sceptical view of the ESO's ability to dispatch assets fairly from recent experience in the dispatch of low-carbon assets in the BM and the ongoing reform process.

Some of our members have raised concerns about the shift towards central dispatch in this second consultation and that ESO has taken on the workstream looking at this area. There is potentially a bias towards central dispatch at the ESO as it would allow them more control over assets and the market. However, as with zonal, no details are available on what central dispatch design would look like in a GB market and the impacts on market participants. This is probably due to the interactions with other options and the early stage of the ESO workstream with Afry.

> **Recommendation:** DESNZ to ensure there is clear representation and oversight of the dispatch workstream being delivering by ESO with Afry.

Additional measures to maintain operability

ESN agrees with the additional measures listed in this section, including:

- An electricity system operability strategy for 2035.
- ESO/NESO to improve forecasting of medium to long-term operability needs, including by location where relevant.

- Improved greenhouse gas emissions reporting on ESO/NESO operability activity across all electricity markets.

We do note that these actions mostly refer to BAU activities or existing published actions (e.g. Centralised Strategic Network Plan), so they don't represent a considerable departure or innovative approach.

The additional measures are also broadly aligned with our priorities, particularly further work on the barriers to co-location and ancillary service provision. These concerns have been documented for many years, and we hope that the REMA process, alongside an updated Smart Systems and Flexibility Plan, can expedite solutions.

The ESN does not agree with the decision to drop giving the ESO/NESO the ability (or an obligation) to prioritise zero/low-carbon procurement. We were disappointed with the statement that enabling this option could “inhibit the ability of the system operator to operate the system efficiently”. This view seems to reinforce the role of high-carbon flexibility in the future and as we approach the target of decarbonising the power system by 2035. This will require significantly more low-carbon flexibility on the system and one of the ways of delivering this would be to focus procurement on those eligible technologies.

> **Recommendation:** DESNZ to reconsider the decision to drop giving the ESO/NESO the ability (or an obligation) to prioritise zero/low-carbon procurement in the REMA process.

One of the core government documents that determines actions and delivery on operability is the Smart Systems and Flexibility Plan. We would like to see DESNZ provide an update on the plan aligned with some of the REMA actions and updated with more recent market priorities. This should be delivered in collaboration with industry, and there could be an opportunity to engage the industry in prioritising the various actions given the limited resources available to the government and wider relevant stakeholders.

> **Recommendation:** DESNZ to publish an update to the Smart Systems and Flexibility Plan, aligned with REMA actions.

Additional ancillary services

ESN prefers open, competitive, technology-agnostic markets and services that match the system requirements and are managed by ESO or DSO. Recent examples, such as Balancing Reserve, illustrate how availability payments can be used to schedule assets at day ahead, improving operability tools for system operators.

In the Carbon Trust Report on the Role of Ancillary Services to Encourage Low Carbon Operability,[28] some new ancillary services were highlighted as warranting further investigation. These include the strategic cycling and short-term (shock absorber) constraint reserve services proposed by Zenobē Energy. A strategic cycling service could help cost-optimise curtailment actions over longer constraint periods (e.g. 24 hours or more), while a short-term constraint reserve service could reduce costs when constraint periods are shorter and help manage short-term spikes in renewable output.

These new ancillary services have the potential to reduce curtailment costs and assist ESO in balancing the system during constraints. We are broadly supportive of further investigation into additional ancillary services that can support new low-carbon flexibility coming online.

Recommendation: DESNZ and ESO to investigate development of additional ancillary services to support the development of further low-carbon flexibility capacity.

Ancillary service reforms

ESN has noticed that the understanding of the impacts of a shift to zonal on the wider set of ancillary services, is understated in the consultation and has not been communicated effectively to the wider industry. The shift to non-firm network access would require service providers to try and guarantee their network access via Financial Transmission Rights (FTRs) or some other mechanism in order to be able to participate in ancillary services. There would also need to be a shift to a more locational-specific procurement of ancillary services, which has been mentioned before but has not been communicated by the ESO or DESNZ to the industry. The volumes of these different services would be part of any Centralised Strategic Network Plan. This change would significantly affect the available revenue stack for flexibility providers and business models.

Recommendation: DESNZ and ESO to clearly outline the impact of a shift to zonal and central dispatch on ancillary service procurement to the industry.

[28] DESNZ, 2024 Report on the Role of Ancillary Services to Encourage Low Carbon Operability

3.5 Options compatibility and legacy arrangements

Responses to questions 25-28

Q25. Which market actors (e.g. generators, suppliers, consumers, government) are best placed to bear/manage different types of risk?

No answer was provided.

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

ESN does not agree that the consultation has identified the appropriate interactions. This is because the consultation has not presented a clear review of the options and lacks detail. Instead, it discusses several specific instances of interactions, such as the interaction between wholesale market design and CfDs. As such, we do not agree that the consultation provides sufficient evidence to conclude that there is a 'high degree of compatibility'.

ESN is concerned that insufficient thought has been put into the compatibility and legacy arrangements. We appreciate the challenges associated with doing so: individual reform options need to be developed in a level of detail that we have not yet seen so far before it is clear how they would interact with each other and what the options are for grandfathering legacy schemes.

> **Recommendation:** ESN would like to see both industry and the government working towards a set of potential reform packages, including detailed outline-designs for each component, a clear narrative for implementation, examples of the interactions between different components of the package, and a set of agreed principles for dealing with legacy support schemes. These should be subjected to a further public consultation before final options are defined.

Q27. Do you agree with our approach to assessing the impact of REMA reforms on Legacy Arrangements?

Addressed in Q28.

Q28. What risks do we need to consider concerning Legacy Arrangements, and how can they best be mitigated?

An important consideration that DESNZ need to be aware of when making any changes to arrangements is the impact of investors' perception of regulatory risk within GB. Over the past decade, GB has enjoyed a positive reputation among investors. This stems from a perception that GB has relative regulatory stability and confidence that arrangements entered into with public energy system institutions will be honoured. This has helped the energy sector to flourish and GB to be seen as one of the leading grid-scale storage markets in the world.

Where REMA reforms require a change in existing arrangements, it will be critical to develop changes alongside detailed discussions with investors in those projects. Many members of the ESN are fund managers themselves and could provide input to this process. The perception of regulatory risk is difficult to quantify. However, that does not mean it doesn't exist, and maintaining the perception that it is low will be critical in drawing in investment to GB in a more challenging macroeconomic environment and an increasingly competitive market between jurisdictions.

> **Recommendation:** DESNZ to work with the investor community to develop legacy arrangements.

Electricity Storage Network

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