REMA Consultation

Solar Energy UK Response

May 2024

About us

Since 1978, Solar Energy UK has worked to promote the benefits of solar energy and to make its adoption easy and profitable for domestic and commercial users. A not-for-profit association, we are funded entirely by our membership, which includes installers, manufacturers, distributors, large-scale developers, investors, and law firms.

Our mission is to empower the UK solar transformation. We are catalysing our members to pave the way for 70GW of solar energy capacity by 2035. We represent solar heat, solar power and energy storage, with a proven track record of securing breakthroughs for all three.

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

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

Solar Energy UK and its members are supportive of DESNZ's position on monitoring the CPPA market. CPPAs have a critical role in driving our transition to net zero. According to Bloomberg NEF, in 2023 corporations announced a record 46GW of solar and wind PPA contracts, with the UK being among the leaders in the global PPA market.[1] While the benefits of CPPAs have been noted by DESNZ themselves it's important to reiterate that renewable CPPAs reduce energy costs, offer revenue stability, protect consumers from price volatility, allow businesses to engage directly with the open market and diversify consumers choices away from traditional energy suppliers whilst simultaneously decarbonising businesses. In this regard, it is important that the CPPA market is not only maintained but actively supported.

As it stands, renewable developers can only offer CPPAs to large offtakers with suitable credit ratings and the ability to sign long term contracts. This means that only large businesses can benefit due to the contractual complexities. However, smaller businesses could also take advantage of CPPAs if the existing barriers were removed. To enable smaller, financially stable, consumers to sign long term PPAs, we urge DESNZ to consider the European Union (EU) Commission's plans to lower credit risks for renewable PPAs[2] .Reducing the financial risk for companies entering PPAs will significantly accelerate the UK's ability to reach its legally binding net zero target.

In terms of the relationship between CPPAs and the suggested REMA reforms, we wish to emphasise the distinct but complementary relationship between a CPPA and a reformed CfD mechanism. There are international examples that could serve as a useful model for the UK. Colombia, for example, has a structure whereby auctions are held with both generators and consumers bidding into the auction. The government effectively acts as the intermediary. The credit risk is then diminished for generators due to the bidding requirements and pooling of offtakers. If the government were to underwrite the consumers' side of the contracts it would resolve the credit risk issue and minimise investor cost of capital.

[1] https://about.bnef.com/blog/corporate-clean-power-buying-grew-12-to-new-record-in-2023-according-to-bloombergnef/

[2] https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1591

note here that we do not endorse the partial CfD option which would ultimately force developers to sign into CPPAs. We develop this in our response to challenge 2.

Regarding further REMA reforms, a move to zonal pricing and central dispatch would create uncertainty. The implications of these changes for the CPPA market need to be considered. Zonal pricing for instance could disincentivise CPPAs in export constrained zones, as lower prices will not guarantee generators suitable returns. This may ultimately force generators to rely on a CfD, therefore increasing the demand / competition for CfDs.

It is critical to note that the REMA process itself has already led to a slowdown in the CPPA market, the uncertainty around the future design of the electricity market has created hesitancy, as there is a fear that radical changes could be implemented. Further uncertainty is expected until DESNZ can provide a clear signal on any transitional arrangements and clarity on the introduction of progressive reforms or a possible future zonal market.

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

A greater CPPA market will distribute the risks and benefits of variable renewable energy differently depending on whether you have signed a CPPA or not. Consumers actively choose their risk and reward profile when signing a CPPA.

For those not under a CPPA, there is little impact as (1) CCPAs that are signed are likely to reduce the capacity of renewables that require a CfD; but (2) the benefits and risk sharing of those CPPAs will be ring-fenced between the renewable project and the consumer involved in the contract.

3. Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction?

Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.

We agree that energy demand reduction is a cross-cutting issue that cannot be solved with policies in one particular place but that delivering a coordinated policy, regulatory and funding landscape across government is the best way to deliver permanent demand reduction.

Within the scope of REMA, flexibility and demand reduction during periods of low renewable availability should be considered. The focus on much of the consultation seems to be on transmission connected generation and demand that can locate as required (hydrogen). We should not lose sight of the opportunities to embed generation close to demand or to create local energy systems and energy parks etc. There need to be options to enable and incentivise this without having to create extensive, parallel, private wire networks so that we can drive the deployment of 'behind the meter' projects.

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

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

The challenges identified by DESNZ are broadly speaking correct, however we do not feel that the list of issues is exhaustive enough. REMA reforms must ensure that any future CfD delivers on its core aims: reducing the revenue risk for generators, in turn lowering the cost of capital and delivering affordable energy to consumers. Within the proposed reforms the transfer of risk between consumers, generators and investors needs to be properly defined and quantified.

While DESNZ notes that volume risk is a key challenge, SEUK and its members would like to see DESNZ's evidence to back up this statement. Similarly, in regards to DESNZ's points around maximising CfD assets' responsiveness to system needs, SEUK strongly suggests that DESNZ undertake a comprehensive review of what the actual barriers are here. The consultation itself implies that the CfD is not a significant barrier to responsiveness, it is just one of several barriers identified. Another challenge identified is how to effectively spread risk across market participants. Within the options identified each market participant (consumer, investor and generator) experiences a different risk level depending on which method is applied, which will imply a cost allocation for that transfer of risk. SEUK members strongly recommend that a standard assessment template is developed and applied, to ensure there is a consistent analysis of the consequences of changes in risk allocation.Furthermore, there are a significant number of issues not addressed within the consultation that we wish to address below:

1. **TNUoS Charges** – TNUoS charges are volatile and unpredictable which poses a major challenge for developers with projects connected to the grid particularly those located in Northern England and Scotland.

- DESNZ acknowledged this challenge and added a 2% and a 1% risk premium to offshore and onshore wind Administrative Strike Prices for CfD AR6 round to reflect this uncertainty for longer term TNUoS charges. Ofgem, in their transmission charging open letter noted that “unpredictability in TNUoS charges has been identified by stakeholders as a barrier to low carbon investments”. They further noted that an effective investment signal from network charges must provide “sufficient predictability that they can efficiently be incorporated into investment decisions”.

- We recognise that changes to improve predictability of TNUoS are underway through TNUoS reform, industry led modifications, and Ofgem’s TNUoS strategic review. However, the transmission charging risk premium must remain in place and under review until there is a clear reduction in the volatility and unpredictability of TNUoS charges. Major investments in the network are planned over the next decade, but their timing, cost, and hence impact on TNUoS charges is very uncertain, impacting generators beyond AR6.

- **2. Ensuring budgets and parameters are aligned with government targets**: The current CfD budget setting process is not transparent and too short-termist with no visibility on how much renewable capacity will be procured, alongside auction parameters that do not appropriately reflect market conditions.The government should link CfD budgets to 2030 and 2035 government capacity targets and set more appropriate auction parameters (reference prices, load factors and ASPs) which reflect market conditions. This will give much needed visibility and certainty to industry.

- **3.Mitigating the risks of price cannibalisation through extending the CfD length:** The consultation correctly recognises that renewables-led price cannibalisation is a real risk. This risk is particularly important when considering renewables that are coming off existing support and entering their ‘merchant tail’.

- As noted in the consultation, the impact of price cannibalisation strengthens the desire for developers to seek a higher strike price across the current 15-year agreement length to protect against this merchant tail risk. Increasing the CfD contract length to align more closely with assets’ operational lifetime would reduce the exposure to post-CfD merchant risk and provide a hedge for consumers from energy market volatility. While the monetary benefits of doing so would be project specific, we estimate that extending to a 20-year contract length could reduce the overall strike price by between 5%-10%. It is also important to note that the current CfD contract length is relatively short compared to other markets globally such as 20-years seen in Denmark, France, Ireland and US, and 25-years in Poland.

- **4. Need for a broader repowering strategy to support existing generation:** The risk of price cannibalisation could also result in existing generation being displaced by new CfD supported generation, at the expense of life extensions, refurbishments, or repowering of existing assets. This could lead to reduced output and even early decommissioning and closure of existing renewable generation that could otherwise continue delivering value to the system. This would bring forward the need for more new and expensive investment in additional generation, increasing the cost of the energy transition. Such a failure to value all low carbon generation equally could lead to a system cost of £48bn by 2050.

- Whilst we recognise, and strongly support, DESNZ's intention to support repowering for onshore wind projects from as early as AR7, DESNZ should commit to developing a broader 'Repowering Strategy' by 2026 – inclusive of solar projects. This would ensure cost-effective decisions are made for life extensions, refurbishments, and repowering as wind assets come off the Renewables Obligation in the late 2020s and CfDs from the early 2030s. This would have an important benefit of enabling the scale up of renewables investment and continuing to pass on the value of renewables to consumers.

- However, it is not just repowered projects that should be eligible for a CfD; in the longer-term, revenue stabilisation should be available for all non-flexible low-carbon projects reaching the end of support. This would protect against price cannibalisation and the risk of early decommissioning and closure ensuring those assets that can continue to provide value to the system are adequately supported, reducing the cost of the energy transition, and protecting consumers from high prices.

- **5.The impact of Government expectations for increasing community benefit payments.** Significant increases in community benefit levels will mean that many projects are unable to continue on a merchant basis. This means that increasing levels of community benefit are likely to result in an increased number of projects seeking a CfD over a merchant agreement. A guaranteed floor price for solar projects under the CfD, designed to accommodate a specific level of community benefit, may enable higher community benefit contributions, but such increases would result in increased consumer bills.

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

While we believe that generators are well suited to adapt to necessary market reforms, we do not believe renewable assets should be exposed to the full range of market signals due to price cannibalisation and negative pricing periods, alongside increasing wholesale price volatility. Exposing CfD generators to the full range of real-time market risks would undermine its core purpose of de-risking investment and it is not clear what, if any, benefits this would bring at a time when scaling up investment is critical, as recognised by DESNZ in the consultation.

It is vital that solar operates within an environment which provides investor confidence. Asset owners will alter their behaviour to maximise revenues and returns. In the event that overall revenue streams are lower / there is heightened revenue risk, there will simply be less capital available for the sector at higher costs. One other consideration is the operational implications of increased flexibility for renewables assets. Generators will not be incentivised to regularly curtail their assets if it leads to additional strain on their equipment and an increase in operational down time and costs.

Again, we urge DESNZ to undertake a detailed review of the full range of barriers to system services. For many of the concerns, it is not clear that, in practice, there is a significant distortion on asset behaviour. It is essential that more evidence is obtained to provide a complete understanding of the actual scale of any distortions and their materiality.

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

Solar Energy UK agrees that ongoing CfD reforms will have a positive impact on addressing the challenges outlined in the consultation. We are very supportive of DESNZ intentions to enable the repowering of existing projects towards the end of their life cycle. The transition to hybrid metering for co-located assets is a welcome development, this may allow CfD assets to better respond to market signals and balance the risk share placed on CfD generators. Co-location supported by hybrid metering could provide generators with the tools to mitigate against future policy risks such as difficulties forecasting the cost of storage technologies, and uncertainty over transmission network and renewable energy build-out. However, we do not believe these reforms alone go far enough to address the challenges identified.

DESNZ estimate in the consultation that 140-174GW of renewable capacity will be required in 2035, up from 56GW in 2023. The magnitude of this deployment will result in an increase in the periods where prices are negative. The volume risk attached to the negative price rule in the current CfD will increase in line with this, resulting in greater revenue uncertainty. As DESNZ note in the consultation, this increased uncertainty will lead to a higher cost of capital which translates into higher CfD strike prices. SEUK does not believe that on-going reforms will address this issue, and we ask that this is considered further. As a general point, a greater focus on planning and grid reform will likely lead to greater investment than CfD reform.

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

At this stage most SEUK members have a preference for a deemed CfD, yet more detail on the design is needed. Regarding the deeming methodology, membership would endorse Option 2 where asset owners would collect site-specific data to input into the deeming methodology set by government. This preference is based on its simplicity in comparison to the other options. The audit from LCCC would mitigate the risk of gaming, this is conditional on the LCCC being adequately resourced. In terms of best outcomes for lower strike prices, option 2 also provides this, whilst the other options increase risk.

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

A capacity-based CfD would be a more fundamental change than the deemed CfD and would raise new challenges that would need to be properly addressed. Based on the information available so far, SEUK does not think that the capacity based CfD offers significant additional benefits to a deemed CfD. The capacity CfD option could be more challenging for investors, as projects become less viable. This is because this option leads into an increase in cost of capital due to higher risks. Key risks include:

- A capacity CfD will require higher bids if the strike price cap is set low and revenue is not shared above the cap.
- A significant level of volume risk will continue to sit with the generator.
- A capacity CfD will be unable to operate on a technology agnostic basis, due to the variance between different technologies' levels of generation and corresponding revenue per unit of capacity. This will need to be independently audited.

·For technologies with high LCOE value, the strike price cap is likely to be close to the required core capacity price. As a result, there will be only a narrow range for merchant revenues above this equivalent floor price, limiting the scope for this mechanism to enable a greater merchant exposure.

·The capacity CfD will be more uncertain and more difficult to analyse than a deemed CfD, as the scale and price of merchant revenues is more uncertain. Developers will be more reliant on forward price curves when preparing bids for a CfD compared to the deemed CfD. That in turn is likely to result in a wider range of bids for similar scale projects than the deemed CfD. Capacity CfD bids are also likely to be more volatile from auction to auction.

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

A well designed deemed CfD provides the most appropriate risk distribution. In the consultation, DESNZ refer to a potential tension when allocating risk between (a) de-risking investment, and (b) increasing assets' exposure to operational risks to maximise their responsiveness to system need. A deemed CfD model addresses both and can deliver lower overall system costs.

As noted in response to question 25, Solar Energy UK supports arrangements that apportion risk to where it can be adequately managed and do not support over exposure of market actors to unmanageable risks that will simply lead to higher system costs. Therefore, and as referred to by DESNZ in the consultation, well allocated risk reduces investment risk and operational distortions, leading to system-wide benefits and minimising consumer costs.

Attempting to allocate risks to generators that they cannot manage will ultimately result in higher consumer costs because generators will tend to pass through the cost of the risk back to consumers with additional risk margins on top.

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

At this stage SEUK believes that a deemed CfD model better serves the aims of REMA in comparison to the other proposed options. It is an evolution of the well-understood existing CfD. The capacity CfD would be a more fundamental change.

In our view, the deemed approach could deliver investor confidence, while incentivising flexibility and participation in other markets such as the balancing mechanism.

Our preference is based on the fact that any additional complexity from introducing a deemed element to the CfD scheme would be offset by longer term certainty for investors, and the overall familiarity with the core scheme. If this approach gains industry consensus, the deemed output approach has the potential to bring significant benefits. Having said this, there are core design questions that need to be addressed before we can wholeheartedly endorse this option

Firstly, to maintain investor confidence it is critical that we remove negative pricing to protect assets against volume risk and allow assets to respond to operational signals. It is also essential that there is a mechanism to protect generators during periods of high prices where an asset is not operational. During these periods, the generator could be liable to significant difference payments to the LCCC when prices are significantly above the deemed CfD. If a site does not operate during such periods due to technical problems and receives no revenues, but is still obliged to honour the difference payments, there could be a very large financial loss. This financial risk is so large that it could prevent investment in the deemed CfD.

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

SEUK and its members do not endorse this approach and request that DESNZ discounts this option from further consideration. Under current arrangements developers can already place part of a project’s capacity outside the CfD and several projects have chosen to do this. Developers themselves can determine what constitutes a commercially viable level of non CfD generation on a case by case basis, which will differ based on technology and scale. In contrast, a partial CfD would impose rigid parameters on all projects. Resulting in suboptimal projects, an increased cost of capital and increased revenue risk for developers. This option would require a complex review by Government of how to appropriately allocate CfD and merchant capacity.

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

Reforming the reference period is unlikely to positively benefit solar generators or improve liquidity in forward markets. Solar generators do not know in advance what the weather conditions will be. Reforming the reference period to include longer term forward prices does not then serve renewable assets. It will likely mean that smaller developers are going to have to trade by shape and re-shape later.

Solar generators will trade when they have a clearer sense of what their output will be, in order to minimise their exposure to volume risk. The change to the reference price introduces new basis and/or volumetric risk for generators which will be challenging to effectively manage. This will drive up the cost of capital for investors.

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

Overall, REMA reforms are likely to make small-scale renewables deployment more difficult.

In general, we expect that REMA reforms will have a similar effect on small-scale renewables as larger renewable generators, as all will face similar challenges in understanding the changes in risks and markets. However, the challenges are likely to be greater for small-scale renewables as they will have less in-house capacity to review such complex changes and, in response, investors will tend to focus on larger projects.

A likely outcome of REMA impact is that it will decrease wholesale prices, particularly in areas with high renewable generation. That in turn will decrease the Smart Export Guarantee (SEG) tariffs for small scale renewable generation that suppliers are able to offer and also the PPA prices that can be offered. Lower wholesale prices on consumer bills also decreases the benefit of the reduction in net import volumes that “on site” small scale renewables can deliver. As a result, REMA is likely to disincentivise building small scale renewables, including community owned projects.

REMA is also likely to increase volatility in wholesale prices, particularly if zonal pricing is taken forward, which will make the value from renewable output less certain and therefore riskier for a supplier to guarantee, which will exacerbate the trends noted above for smaller generators – including community owned projects.

Specifically, for CPPAs, it is already a challenge to deliver workable solutions for small renewable sites. Where sites are too small to deliver the total requirement of a CPPA, it is necessary to combine generators into an agreement. More complexity is likely to incentivise offtakers to increase the minimum volume requirements for setting up a CPPA. Corporate customers are also more likely to avoid smaller volumes and/or take a simpler procurement approach, such as a REGO backed supply agreement, rather than a dedicated CPPA.

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

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

We support Government's decision to retain an optimised form of the CM as the primary mechanism for capacity adequacy in GB. We also welcome Government's confirmation that the reform will result in a single auction design with multiple clearing prices and minimum procurement targets for desirable characteristics.

It is difficult to provide a detailed answer for this question without firm proposals from Government on which criteria would be used to set minima for the CM auctions. We understand that Government is undertaking further work to develop this, and we encourage this to be published and consulted on as soon as possible.

In the meantime, we would support CM auction procurement minima based only on the carbon status of the capacity participating. We believe this would be the simplest option, with the lowest potential for causing unintended consequences and/or liquidity issues in the CM auctions.

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

We believe that procurement in the auctions based on numerous flexibility characteristics (beyond just low and high carbon) could introduce risks and unintended consequences, including relating to secondary trading in the CM.

This could outweigh the improvements being considered for secondary trading via the Capacity Market Advisory Group (CMAG) and Ofgem/DESNZ workstreams, which we believe would be a concern for many CM participants as an effective secondary trading market is of considerable value in mitigating the risks of CM non-delivery.

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

Overall, we support the proposal to introduce a lower carbon intensity emission limit in the CM from the 2034 Delivery Year, and we believe the proposed intensity limit (<100gCO_2/kWh) is appropriate based on current data.

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

We support the proposal in principle to align with GB's net zero ambitions, subject to security of supply considerations.

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

The potential availability of support from the CM for refurbishment/conversion and the establishment of a firm emissions limit are important measures which should encourage the owners of unabated gas plant to further consider the scope for conversion.

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

Any business case for conversion will need to consider the likely CM out-turn price, the potential impacts of CM design evolution, wholesale market changes and technology/sector specific risks relation to CCS capture or low carbon hydrogen.

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

We support the choice of the Optimised CM as the right approach for supporting the procurement of capacity and ensuring security of supply in the GB electricity market. But further work is required to define and clarify the operation of an Optimised CM in more detail and this will help the market understand and quantify the likely level of future support an Optimised CM could provide for distributed low carbon flexibility options.

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

The proposed package of measures set out in REMA have the potential to deliver sufficient volumes of low carbon dispatchable/flexible technologies while ensuring security of supply.

.However, we consider this potential is subject to further details of the various measures, which need to be circulated to all stakeholders for further review, prior to making a policy decision.

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

We remain sceptical about the benefits of a zonal system. Zonal pricing would introduce additional uncertainty into the market, raising the cost of capital for renewable energy at a time when we need to deploy around 10 gigawatts of renewable electricity generation capacity each year until 2035 to meet our targets and deliver a lowest cost clean energy system for billpayers.[3]

The impact of zonal pricing also needs to be considered within the context of investor nervousness to allocate capital to infrastructure given rising interest rates. The scale of capital required for the UK's decarbonisation means that the sector needs to be careful about increasing risks - to ensure that the renewable energy sector does not become considered an unattractive market in which to invest.

Furthermore, within the LCP Zonal Analysis which accompanies the consultations, the modelled benefits have not accounted for grandfathering of existing schemes which would significantly diminish the theoretical benefits of the move. Not committing to grandfathering would exacerbate the damage to investor confidence and cost of capital increases. A transition to a zonal system will also likely take several years to implement and would slow our transition to a net zero system. Comparatively an incremental move to an 'enhanced national market' could deliver benefits to consumers more quickly. Although what constitutes an enhanced national market needs consideration and must accelerate - not hinder - solar project if we are to meet net zero.

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

Solar Energy UK agrees with government's assessment that implementation of a zonal locational pricing market is likely to be more challenging and will take time to implement; there is greater potential for negative impacts on investor confidence and certainty.

[3] https://www.blog.renewableuk.com/post/the-costs-of-locational-masexc rginal-pricing-outweigh-the-benefits-it-s-time-to-look-at-other-reforms

There are benefits to bringing forward reforms to the national wholesale market as these can deliver useful and material improvements in a much shorter timescale than zonal pricing and with fewer challenges.We also consider that delivering an enhanced national market could capture some or all the benefits that zonal pricing may bring.

Similarly, it is key to understand how the Strategic Spatial Energy Plan (SSEP) will fit into REMA reforms. The ability to create innovative local energy systems combining hybrid generation and co-located or local demand could provide some of the answers but spatial planning is still evolving and it is important that the market tools are kept simple and clear to ensure there are options to give the right signals at the right times to different technologies.

Potentially, a spatial plan that considers grid, land, consenting and resources in a holistic way – what, when and where - would help all of the relevant market players from demand customers to supplier, generators and network operators to invest in a more coordinated way. For Solar at least, the fundamental forces driving location are grid availability and the likelihood of planning consent. To deliver net zero we need more than just a price incentive, we need a planning system and grid system to work alongside it.

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

We welcome work to date by the ESO to bring forward important reforms to balancing services to enhance electricity system operability. Some of these changes are already delivering significant positive benefits to contain growth in balancing costs such as the suite of dynamic frequency response services, while others such as Balancing Reserve have only just been launched. In addition, Ofgem have taken action on the regulatory framework such as the Inflexible Offers Licence condition and providing additional guidance on the Transmission Constraints Licence condition. It is important that these developments have time to work and their benefits are taken into account when assessing the case for potential further reforms.

Solar Energy UK does not agree with the idea of central dispatch. We have not seen a demonstration of the ESO having the tools and capability to effectively manage this and it would have very complex interactions with other options and processes. There has not been enough information provided on what this would entail. There was meant to be a paper published by the ESO in Spring 2024 but we have not seen this and so an informed debate or consultation cannot be held. This should be made publicly available as soon as possible.

Options compatibility and Legacy Arrangements

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

The general principle of efficient risk allocation is to place risks on those who are best placed to manage them. In the context of the options being considered within REMA we would highlight that generators consider market risks at a very early stage of project development and these risks inform the location, scale and nature of any proposed development and the allocation of capital between different geographies and technology options. Locational signals are therefore best placed on generators at an early stage, where these can influence the chosen location of development.

Once a final investment decision has been taken to build out and operate a generation development, the capability of that generator to respond to market and locational signals is much more limited, especially in the case of weather dependent forms of renewable output.

Placing additional risks on generators will, in all circumstances, increase the cost of capital of new development. In some cases this will be reflected in a requirement for higher returns before investment funds are committed, and this in turn will be reflected in market outcomes in a variety of ways such as higher strike prices within CfD auction round competitions or higher capacity market clearing prices – adding costs back to electricity consumers. In other cases higher risks will lead developers/investors to delay or abandon projects entirely as too risky, or too unattractive, relative to alternative options available in other markets or geographies.

The REMA consultation rightly recognises that there is a balance to be struck between the benefits that can arise from exposing generators to market and locational signals and the risks to investment that can arise from increased revenue uncertainty. We do not argue that generation development should be insulated from all market or locational risks. However, we do suggest that government should very carefully examine the cumulative revenue risk likely to be associated with any proposed REMA package of reforms.

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

We are unable to comment on the compatibility of the remaining options due to insufficient detail within the consultation. Our ability to comment has also been impacted by the short consultation window. We would like to engage with DESNZ meaningfully after the consultation period and continue to engage on the next phase of REMA and it's implementation.

Given the breadth of reforms that still remain on the table, SEUK would like to request an additional consultation by DESNZ with an even narrower yet more detailed range of reforms. It is absolutely vital that the solar industry has the opportunity to feed into the final REMA package given the significant impact on solar generators and their mandate to deliver 70GW by 2035, on the way to meeting net zero.

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

It is crucial for DESNZ to carefully assess the impact on existing legacy arrangements and assets. In cases where the impact is significant, DESNZ should explore ways to mitigate or exempt legacy assets from upcoming changes. We firmly believe that DESNZ should commit to grandfathering all contractual agreements made under existing government support schemes until there is clarity on major reforms, such as a potential shift to zonal pricing.

Additionally, DESNZ must take care not to undermine the commercial viability of operational assets, and those under construction, ensuring they are not left stranded. Achieving this delicate balance will be a complex task, and the government needs to transparently demonstrate how it plans to implement grandfathering to maintain investor confidence. The other concern we have is that projects that are currently in development but not built (of which there is a significant amount) will need clarity and potential grandfathering of some type to enable development to continue without creating significant risk whilst this consultation and reform continues.

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

The many significant reforms being considered by REMA have clear potential to bring substantial revenue risks to a wide range of generators in the GB market, and these risks are by no means limited to those generators operating within existing support mechanisms. If very substantial negative impacts on investor confidence in the GB market are to be avoided, then significant interventions will be required by government to protect and “grandfather” existing and committed development – this protection would typically be required not only through the period of transition to new arrangements, but for many years beyond.The REMA changes most likely to give rise to extensive market wide requirements for some forms of protection are a move to zonal pricing, any network access reforms which remove firm access rights for existing generators, and any move to centralised dispatch.

A failure to provide material protections for existing generators while undertaking significant REMA reforms will very likely give rise to a substantial deterioration in investor confidence and associated increases in the cost of capital (or general willingness to invest). Such a reduction in those willing, or able, to invest is anticipated to be well above the very modest cost of capital increases referred to by both the DESNZ funded LCP Delta supported AFRY studies on locational pricing as being sufficient to negate any modelled benefits arising from a move to locational pricing. Indeed, providing the necessary insulation for projects currently operational or under construction and, to a lesser extent, those at earlier stages of project development, will materially reduce the likely benefit of such reforms, diluting, or negating, the case for introducing them.

This highlights the challenges which would be inherent in simultaneously delivering very substantial market changes where the case for reform rests on sending new operational and locational signals to market participants, alongside measures which protect large numbers of market participants from these new signals, as they have invested on the basis of existing market rules and principles.

This fundamental difficulty is a key reason why SEUK favours an evolutionary approach to reforms in the current GB market context.