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07 May 2024

Sent by email to: Robert.Hewitt@energysecurity.gov.uk
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Dear Rob

RE: Review of electricity market arrangements (REMA): second consultation

We are pleased to respond to the second REMA consultation. Centrica continues to assess REMA options through the lens of our company purpose: *Energising a Greener, Fairer Future*. To deliver on our purpose, we need market frameworks that are predictable and therefore investable. It is important not just that REMA outcomes are fair to consumers, but also that they are seen to be fair. Without this perception of fairness, we risk losing public support for the investment needed to achieve a fully decarbonised energy system.

Centrica operates across the GB electricity value chain as: an investor in renewable and flexible generation assets; a trader; an optimiser; and a supplier. We have around 10 million customers, most of whom are residential energy customers in GB. We have around 13GW of renewable assets under management across Europe. Through our green-focused investment strategy we will build investment levels to £600m-£800m per year until at least 2028. Over 50% of our capital expenditure is expected to go into green taxonomy eligible projects, compared to only 5% two years ago.

In this cover letter we summarise:

1. The approach that we believe DESNZ should take to shortlisting reform options, including shortlisting decisions we agree with;
2. Why zonal wholesale pricing should not be considered as a reform option; and
3. What improvements should be shortlisted to improve locational investment signals and dispatch in an enhanced national market.

We attach the following appendices and supporting documents:

- In Appendix 1 we show some striking differences between predicted generation location in a zonal market between the FTI[1] and LCP Delta[2] assessments of zonal pricing.
- In Appendix 2 we provide our responses to the individual consultation questions.
- We attach two independent reports by Frontier Economics that we have previously submitted to DESNZ on the interaction between locational wholesale pricing and the retail price cap. A third, new report on self-dispatch vs central- dispatch will be submitted separately to DESNZ.
- We attach an independent report from NERA Economic Consulting that shows the projected evolution in hedging costs under the default tariff cap as the growth in intermittent generation increases.
- We attach a standalone Centrica paper discussing the benefits of Power Purchase Agreements (PPAs) and barriers to their growth in the UK.

1. The approach that we believe DESNZ should take to shortlisting reform options, including shortlisting decisions we agree with

As outlined above, we aim to deploy significant amounts of capital in the UK energy system, helping to drive the green transition. As investors have emphasised throughout the REMA process, there is a link between regulatory certainty and confidence to deploy capital in the UK. Centrica is a supporter of reform if reform proposals can be shown to be in the long-term interests of consumers; indeed, we have actively advocated for energy market reform in a number of areas.[3] However, to justify fundamental reform, a high threshold must be satisfied to show that reform will deliver significant benefits to consumers in practice, as well as in theory. This threshold is naturally higher at this stage in the transition to net zero, when such significant investment in new energy infrastructure is urgently needed.

Consistent with our letter of 21 July 2023, we continue to urge the Government to ensure that wholesale electricity market reforms are complementary to – and at least compatible with – the retail electricity market. As we have shown previously, it is difficult to justify supporting both a retail price cap and locational wholesale pricing where demand is exposed to the locational price. DESNZ's "Future default tariffs: call for evidence" published in February this year[4] does not mention REMA. Nor does this REMA consultation mention the Future default tariffs: call for evidence. These reform programmes need to be joined up urgently and explicitly. Holistic thinking is needed to deliver an electricity market design that best protects current and future consumers.

We appreciate the huge amount of work and constructive engagement with industry that your team has undertaken since the first REMA consultation. We welcome the direction of travel

[1] FTI (2023). Locational pricing assessment in GB: Final modelling results
[2] LCP Delta / Grant Thornton (2023). System Benefits from Efficient Locational Signals
[3] Centrica (2023). Changes are needed to make the energy sector simpler and more transparent
[4] DESNZ (2024). Future default tariffs

you have taken in moving from the long list of reform options to the now much shorter list. In particular, we agree with the following shortlisting decisions:

- **We agree that the Capacity Market (CM) should be retained. The CM is needed to ensure that flexible assets with higher running costs and lower running hours are economic, so as to be available during periods of scarcity.** We agree that including low-carbon minima in the CM is the best market-based option to incentivise low-carbon flexibility. The low-carbon minima should replace bilaterally negotiated dispatchable power agreements. It appears to be implicit in the consultation that the delay to CM emissions limits for new plants will allow new CCGT(s) to get CM contracts. We request clarity that the emissions limits will not impact on new-build CM plant for the duration of their 15-year contracts.
- **To the extent that Contracts for Difference (CfD) continue to be needed to de-risk investment in intermittent renewables, we agree that they should be reformed to incentivise merchant-like behaviour, particularly forwards-hedging.** Of those shortlisted, conceptually our favoured CfD reform option is the capacity payment, by virtue of its relative simplicity. We are also interested in the CfD-merchant hybrid option. If the fundamental CfD design remains as is – i.e., protection from price risk via a fixed strike price – the reference price should be amended to encourage more forwards hedging. At this stage, we are unable to support the deemed CfD because of its complexity and the potential unintended consequences of basing revenues on deemed output.
- **We welcome DESNZ's recognition of the important role that PPAs can play in unlocking investment in subsidy-free renewables. We would like to see the Government take actions to remove barriers to this private investment.** Such actions should include ensuring that CfD-type support is only provided where it is demonstrably needed,5 and developing credit guarantees to broaden the range of counterparties that are able to access PPAs.
- **We agree that nodal pricing should no longer be considered as an option.** We agree that nodal wholesale pricing would undermine investor confidence due to the unpredictability in revenues for assets exposed to those signals.

2. Why zonal wholesale pricing should not be considered as a reform option

We urge DESNZ to reject zonal wholesale pricing as a reform option, for similar reasons to the rejection of nodal. Beyond, perhaps, improving the dispatch efficiency of interconnectors, we do not agree with the qualitative benefits case for zonal as articulated in LCP Delta's ("LCP") modelling for DESNZ, let alone the quantitative.

LCP suggests that constraint costs effectively transfer from generator payments to consumer savings in a zonal market. LCP also suggests that significantly more onshore wind locates in the North of Scotland under a zonal compared to a national market. We do not believe it is plausible that such additional volumes of generation will locate in Scotland if they are exposed

[5] E.g., to technologies that have not reached maturity and capital-intensive projects.

to the zonal price. Generator revenues from today's constraint payments are likely to need to continue, or be replaced in some way, to guarantee construction of sufficient renewables capacity to meet net zero.

There are striking differences between the results of LCP's analysis for DESNZ and FTI's analysis for Ofgem. For example:

- LCP predicts that batteries will relocate *away from* Scotland following the introduction of zonal wholesale pricing, whereas FTI suggests that they will relocate *into* Scotland; and
- LCP predicts that solar farms will relocate *away from* the southernmost zone of England following the introduction of zonal wholesale pricing, whereas FTI suggest they will relocate *into it*.

These striking differences demonstrate how difficult it is to confidently predict any benefits of zonal wholesale pricing and how sensitive the findings are to assumptions. The difference in findings between the two studies also demonstrates the uncertainty that such reforms would create for potential investors in new generation assets and is a good illustration of the chilling effect such reforms will subsequently have on investments that are of critical importance to achieving net zero.

There are also important omissions from LCP's assessment of the impacts of zonal pricing. For example, it does not properly consider the interactions with the retail market, and entirely omits any discussion of the compatibility between the retail price cap and zonal wholesale pricing.

Perhaps LCP does not discuss the retail price cap because it assumes that only electrolyser demand is exposed to the zonal price. However, DESNZ has not ruled out the option that demand other than electrolyser demand is exposed to the zonal price. It is challenging to reconcile the retail price cap and effective retail competition with demand being exposed to a locational wholesale price, as the two reports by Frontier Economics we submitted to DESNZ last year demonstrate. We do not envisage the p/kWh price cap being removed in the medium term. Unless DESNZ disagrees, we recommend that REMA reforms are compatible with the continuation of the p/kWh price cap.

LCP's assessment of zonal does not fully consider the impact of zonal wholesale pricing on investment in existing nuclear power stations. For example, Sizewell B is currently anticipated to continue generating until 2035, with the potential to extend by 20 years to 2055 if economically viable.[6] Moving to zonal wholesale pricing would have implications for the economics of nuclear assets that are not insulated from the zonal price by either a CfD or Regulated Asset Base (RAB) support model. Zonal wholesale pricing may also affect the functioning of CfD and RAB based support for nuclear assets via the reference price.

[6] EDF (2024) UK Nuclear Fleet stakeholder update. Executive Summary states: "The focus for the Sizewell B power station is on operational excellence and investing to enable a potential 20-year life extension, out to 2055. This decision is subject to agreeing the appropriate commercial model to ensure such an extension is viable".

LCP's assessment of zonal also does not quantify the upward pressure on consumer prices that would result from a reduction in forward market liquidity in a zonal market. To the extent that DESNZ continues to consider zonal pricing as a reform option, it should seek to quantify the impact of the reduction in market liquidity on consumers and use empirical evidence to inform that assessment. As part of the assessment, we strongly encourage DESNZ to look at lessons learned from zonal pricing being introduced in other jurisdictions (e.g., Sweden) and how it has impacted liquidity, retail competition, investment in renewables and constraint costs.

3. What improvements should be shortlisted to improve locational investment signals and dispatch in an enhanced national market

We agree with DESNZ that there is scope to strengthen locational investment signals and make dispatch more efficient.

- **We would endorse providing clearer, stronger and more predictable locational investment signals through charges applied to generators.**
- **We strongly encourage the UK Government to agree with their counterparts in other Governments to couple interconnected electricity markets.** Market coupling would improve the efficiency of interconnector dispatch.
- **We strongly encourage the future National Energy System Operator (NESO) to continue to improve the efficiency of the Balancing Mechanism** (BM) by reducing skip rates, removing barriers to the participation of demand-side response (DSR), and enhancing its technical and operational capabilities.
- **We encourage further development and expansion of locational constraint markets (e.g., in Day-Ahead) to take pressure off the Balancing Mechanism.** Such markets would also give flexibility providers more foresight of potential revenues in different locations.

We do not support the introduction of central dispatch and do not believe that any benefits of introducing central dispatch would outweigh the profound uncertainty and widespread disruption such an intervention would create. We have commissioned Frontier Economics to consider the potential advantages and disadvantages of introducing central dispatch. Frontier's report – which we will submit separately to DESNZ – contains a section that discusses how to improve the efficiency of dispatch within the existing paradigm.

4. DESNZ's focus should remain on enabling grid infrastructure and connections

Whilst it is prudent to consider whether electricity market arrangements are fit for purpose, there is a risk that REMA unduly distracts from the construction of an electricity grid that is needed to deliver a secure zero-carbon power system. Indeed, systematic under-build of the grid over the last decade or two is a key driver of REMA, since under-build of the grid has placed an upward pressure on constraint costs. We strongly urge DESNZ to focus all available resources on enabling grid investment and swift connections for projects that are ready.

As Ofgem has recognised in its recent Multiyear Strategy, “Achieving the scale of infrastructural change needed at pace and fair cost requires a decisive move in favour of a strategically planned, centrally co-ordinated, and integrated system”.[7] A move to zonal wholesale pricing would be in tension with, and a likely distraction from, the more centralised strategic planning that Ofgem says the system needs.

I hope that our response will help you to continue to filter and develop reforms to the GB electricity market. I look forward to discussing our views further with you in due course.

Yours sincerely

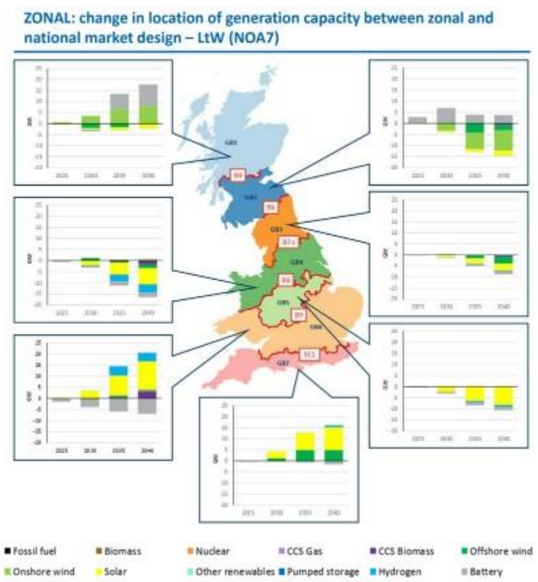
Alun Rees

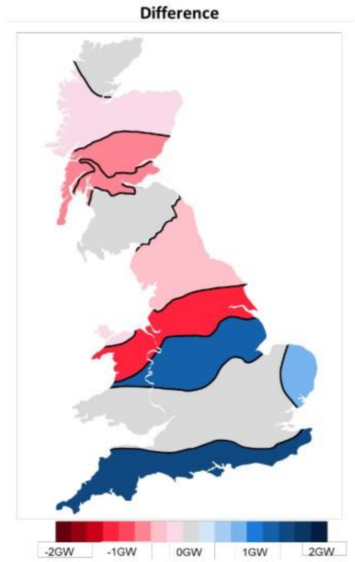
Head of Wholesale and Retail Market Design and Policy

[7] Ofgem (2024) Multi year strategy, p. 34

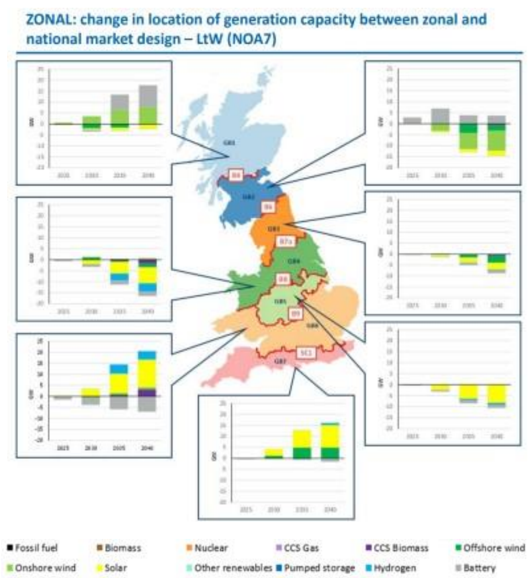
Appendix 1 – some differences in predicted generation location in a zonal market between the FTI and LCP Delta’s assessments of zonal pricing

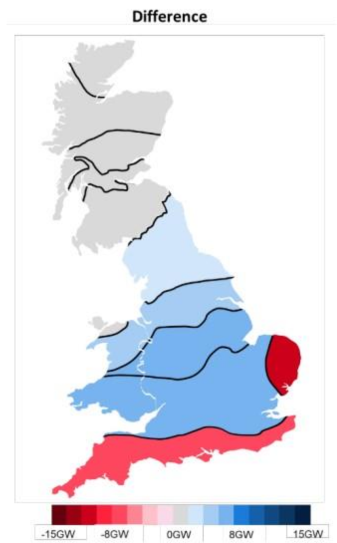
Batteries – the chart on the left shows FTI’s view of relocation of batteries (grey) in a zonal market compared to a national. The map on the right shows LCP’s view. FTI predicts significant relocation of batteries to Scotland; LCP predicts relocation away from Scotland.





Solar – the chart on the left shows FTI’s view of relocation of solar (yellow) in a zonal market compared to a national. The map on the right shows LCP’s view. FTI predicts significant relocation of solar to the southernmost zone of England. LCP predicts relocation of solar away from southernmost England.





Appendix 2 – Centrica's responses to consultation questions

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.

We welcome DESNZ's recognition of the important role that commercial power purchase agreements (PPAs) can play in unlocking investment in subsidy-free renewable energy (RES). We would like to see the Government take action to remove barriers to such market-based renewables growth. Such actions should include ensuring that CfD-type support is only provided where it is needed. The Government should also develop a framework for credit guarantees to broaden the range of eligible counterparties for PPAs. Removing these barriers will be important if GB is to achieve the required 140-174GW of installed renewable energy capacity by 2035 (vs 56GW today).[8]

While subsidies have played a key role in ensuring renewables growth and reducing technology costs, in the future, achieving high levels of investment will require both government-backed (via a reformed CfD) and market-based (via renewable PPAs) instruments for underwriting renewables investment. It would be a mistake to rely solely on CfDs, which would crowd out opportunities for a demand-driven, market-based approach.

We consider that market-based mechanisms such as PPAs can offer a number of benefits over CfDs. Currently, CfDs reduce forward market liquidity as they remove incentives from generators to sell volumes in the forward market. This limits the volumes available to suppliers and businesses for hedging price risks, thereby increasing costs and uncertainty for consumers. With the share of CfD-supported generation expected to increase in the future, their distortive impact on market efficiency and liquidity will only grow.

In contrast to CfDs, PPAs offer hedges to the demand side, e.g., to corporate and industrial consumers who need visibility on their energy costs to manage business risks, improve their competitiveness and source green electricity. In certain cases, intermediaries can also hedge PPA volumes on the traded forward market, thereby adding to its liquidity.

In the rest of our response to this question, we discuss:

- The different types of PPAs and their benefits,
- Their growth potential,
- Barriers to growth,
- Interconnection with other REMA reform options, and
- How we see PPAs evolving over time.

[8] DESNZ (2024) Review of Electricity Market Arrangements: second consultation

Renewable PPAs: definition and benefits

While the consultation refers to CPPAs, i.e., Corporate PPAs, this is only one (albeit a common) type of PPA.

In essence, renewable PPAs are commercial contracts between a producer and an energy buyer looking to specifically procure renewable electricity and/or hedge against short-term price volatility. Buyers are usually corporate or industrial consumers, but could also be small and medium-sized enterprises (SMEs), municipalities, etc. The length of the contract can vary from between a few months to 15 years or more. Contract structures can also vary and offer flexibility, which is necessary to define contractual terms in line with the parties' abilities to manage the associated risks. This is a key advantage of PPA contracts.

PPAs offer developers revenue stabilisation, which helps them to obtain project financing and reduces the cost of capital. For businesses (buyers), they are a hedging tool, which shields them from price volatility, while also supporting their decarbonisation targets via renewable energy supplies.

In addition to corporate and industrial buyers, intermediaries (utilities, traders) are also a common type of PPA offtaker. Essentially, intermediaries sit between producers and consumers and have an important optimisation function. For example, an intermediary can buy all the output of a generator in a fixed-price pay-as-produced renewable PPA, which removes price risk from the producer. The intermediary can then aggregate volumes from the generation side to structure a corporate PPA or sell the volumes to several buyers with smaller consumption profiles. It could also place the volumes on the forward market and sell them more incrementally. Risks are warehoused and managed by intermediaries through their portfolio and trading activities.

PPA contracts can also be restricted to the provision of route-to-market (e.g., for projects under a CfD that need a contract to market their power, while the Government takes on the price risk by offering a floor price) or balancing services. Further information on the features and benefits of renewable PPAs is included in our standalone paper attached to this response.[9]

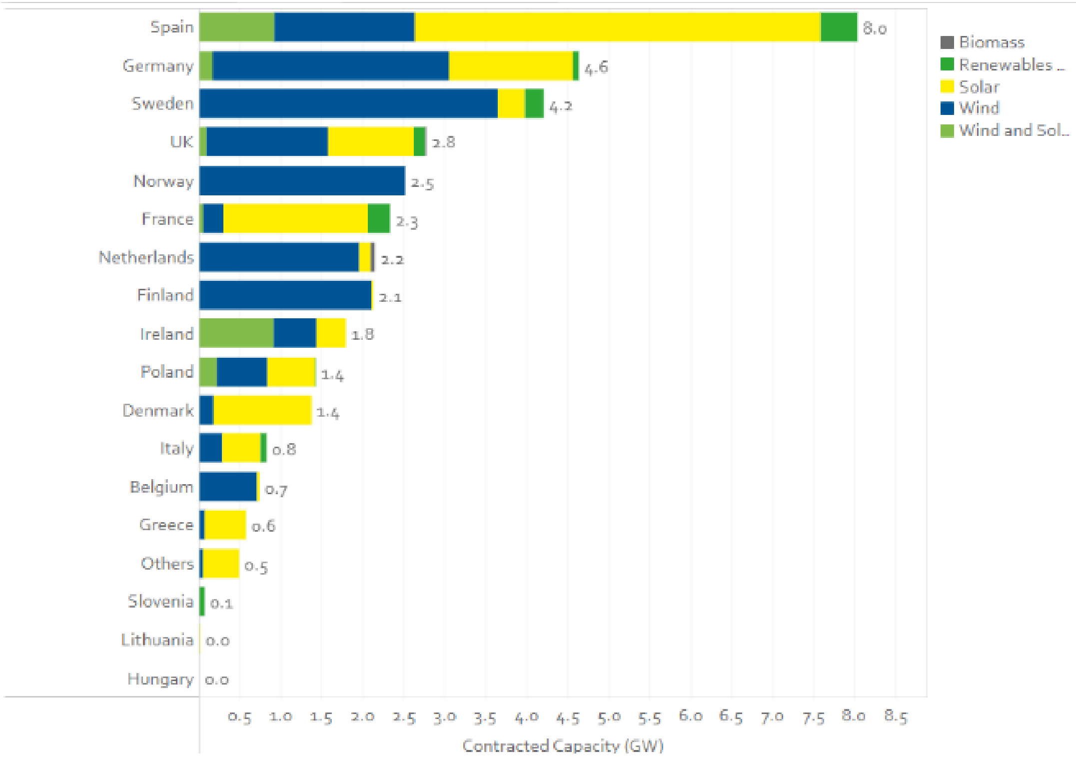
a) Potential for renewable PPA market growth

We consider the renewable PPA market to have a strong growth potential. The UK market is among the top performers in Europe, with 2.8 GW of total contracted capacity in the period up to 2023 (see Figure 1).[10] However, this represents only a small part of the total installed renewable energy capacity in the UK, which amounts to 56GW.[11] At the same time, the 2035

[9] Centrica (2024) The role of PPAs in decarbonising the UK power grid
[10] This figure covers only PPAs able to de-risk investment (i.e., no route-to-market PPAs for subsidised assets, or PPAs for balancing services only); most volumes cover PPAs with new assets (only a small proportion concerns PPAs with assets that have reached the end of their support (up to 5 years after end of support)); the figures are based on publicly disclosed information on contracted volumes, which means that the actual figure is higher.
[11] DESNZ (2024) Energy Trends March 2024

net zero target for the electricity sector means that RES capacities need to grow considerably in the next decade with 140-174GW of installed capacity required by 2035.[12]

Figure 1: PPAs Total contracted capacity (GW) by country, 2023 data[13]



Given the volume of required renewables investment in the next decade and the preference of lenders and some investors for longer-term revenue certainty, significant demand is expected from developers for long-term contracts to de-risk renewable energy projects. Currently, the availability of government-backed CfDs (which remove price risk from developers and transfer it to electricity consumers) has a dampening effect on the demand for PPAs. Limiting the availability of CfDs (e.g., to technologies that have not reached maturity and large-scale, capital-intensive projects), would help to open up the supply side of the PPA market.

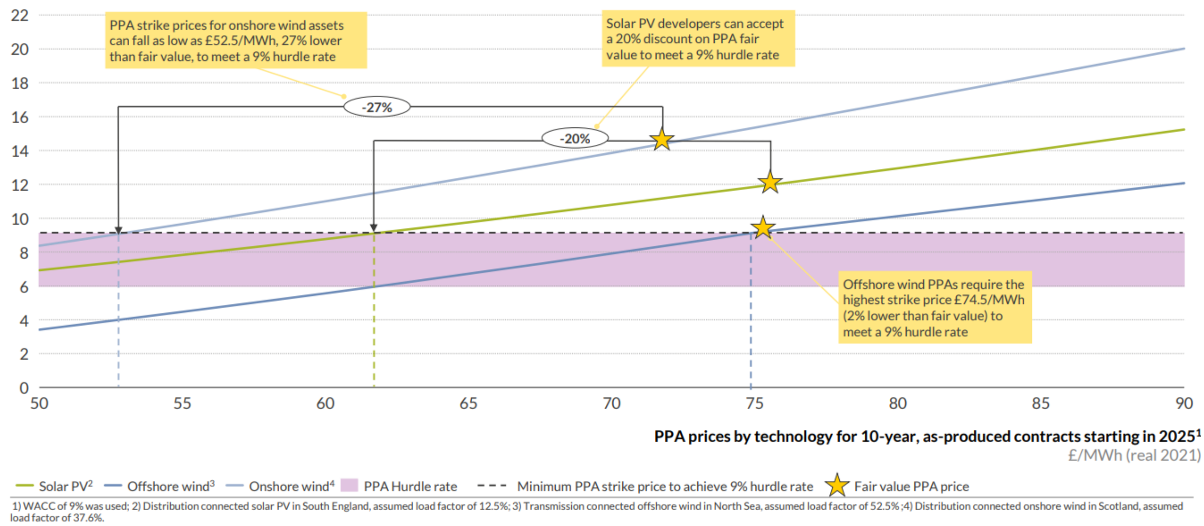
A competitive renewable PPA market could deliver renewables growth, while ensuring competitive prices for consumers. This has been the case for mature technologies such as onshore wind and solar for some time now, but it is also increasingly the case with respect to offshore wind projects.14 As illustrated in Figure 2, Aurora Energy Research estimates that competition could reduce PPA strike prices by more than 20% for onshore wind and solar compared to their fair value, and by 2% for offshore wind.

[12] DESNZ (2024) Energy Trends March 2024

[13] Re-Source Platform (2024) PPA deal tracker - RE-Source Platform

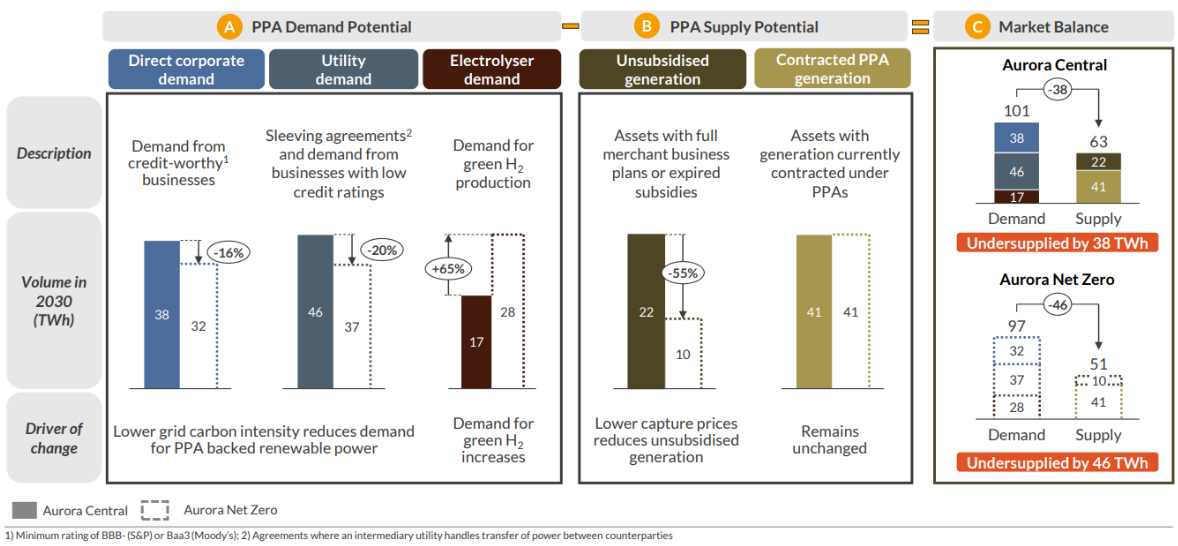
[14] Pexapark (2024) European PPA Market Outlook 2024. Pexapark quote 1.73WG of offshore wind contracted across 14 deals in Germany. The Netherlands is also mentioned in relation to growth in offshore wind deals.

Figure 2: PPA projects internal rates of return (IRRs) by technology for 10-year as-produced contracts starting in 2025, IRR %, pre-tax (real 2021)[15]



On the demand side, Aurora Energy Research estimates that the GB PPA market will be undersupplied by 38TWh in 2030, with the deficit increasing to 46TWh in the more ambitious Net Zero scenario (Figure 3). Growth is driven by credit-worthy businesses – 38TWh, but also, notably, by businesses with low credit ratings (increasing to 46TWG, in combination with demand for sleeving agreements). The ability to capture opportunities with respect to the latter would depend on efforts to develop a framework for credit guarantees that could facilitate the access of such businesses to the PPA market.

Figure 3: Aurora Central case for GB PPAs[16]



In our view, some of the key drivers for PPAs growth include:

- **Business electricity users' need to hedge against price volatility.** Electricity utilities and traders can also contribute to the effective management of risks and

[15] Aurora Energy (2022) Role of PPAs in the GB Power Market
[16] Aurora Energy (2022) Role of PPAs in the GB Power Market

facilitate a better match between the needs and preferences of producers and consumers.

- **Increased corporate net zero commitments and targets**. Renewable PPAs help to reduce end user companies' carbon footprints.
- **Smaller and medium-sized businesses increasingly interested in the hedging and carbon benefits outlined immediately above.** Multi-buyer PPAs (also known as aggregated PPAs) pool demand and could facilitate the participation of a wider range of buyers in the market. However, as we discuss later, growth in this area depends on efforts to provide a framework for credit guarantees.
- **Growing demand from developers of green hydrogen**. The Government's ambition for up to 10GW of low carbon hydrogen production capacity by 2030 is also expected to create strong demand for PPAs. Green hydrogen developers would be looking for long-term, cost competitive renewable energy agreements that meet the requirements of the Low Carbon Hydrogen Standard. Aurora Energy Research estimates demand from green hydrogen production to amount to 17TWh in 2030 (and 28TWh in the Aurora Net Zero scenario).
- **Growing demand for hybrid PPAs**. There is growing interest in combining renewable energy production with storage through the so-called hybrid PPAs.[17] Hybrid PPAs offer a better match for the usually stable consumption profile of buyers compared to output from intermittent renewable energy assets alone, reducing market exposure for the counterparties. Hybrid PPAs also have benefits for grid stability, alleviating the pressure on the network operator to match supply and demand at a system level.
- **Growing demand from 24/7 green energy purchasing**. Companies are starting to show an interest in more granular temporal matching of their energy consumption with renewable energy production. While this is still a niche area, studies show that in addition to improving carbon accounting, such PPAs can also provide hedging benefits.[18]

b) Barriers to PPA growth

While we see considerable potential for PPAs growth in the UK, there are currently barriers to unlocking this potential. To address these barriers, we would urge policymakers to:

- **Ensure a stable regulatory and policy environment**. The Government should avoid market interventions and radical changes to the market design that would undermine contract and investment decisions and create investment uncertainty; the Government should uphold political commitments to legally binding decarbonisation targets to provide certainty about the strategic direction to industry.
- **Reform the CfD scheme** to incentivise forward hedging and focus subsidies on technologies where the market is unable to deliver the policy outcome alone.

[17] Pexapark (2024) European PPA Market Outlook 2024
[18] Euroelectric (2024) Improve your energy procurement contracts with 24/7 carbon free energy matching; Pexapark (2023) CFE Hedging Analysis

- **Develop a framework of credit guarantees to support PPA uptake** among a more diverse range of offtakers.

Regarding the other two areas that the consultation identifies as challenges to PPAs growth – transaction costs and contract length/demand mismatches – we agree with the Government's view that the market can develop effective mechanisms to address them. No intervention is required.

c) Interconnection with other REMA reform options

A CfD design which incentivises assets to maximise revenues from the market – such as a capacity-based CfDs – may encourage assets to secure at least part of those revenues through a longer-term commercial PPA. Partial CfDs (covered in more detail in our response to Q.11) could also unlock opportunities for PPAs. In doing so, both of these reform options (possibly also in combination) could contribute to improving hedging and reducing market distortions.

Splitting the GB market into wholesale pricing zones is likely to considerably slow PPA growth. Moving to a zonal market would significantly impact on liquidity of multiple bidding zones, increasing risks to investors and a reducing the potential for matching counterparties that are able and willing to manage the associated risk. This would in turn lead to an increased need for CfDs and a subsequent cost-allocation to electricity consumers where firms would have been willing to cover this cost in an efficient and liquid market.

d) Evolution of PPAs as the grid decarbonises

As the grid decarbonises, cannibalisation risk may increase, which is a key challenge to renewables growth. PPAs themselves are a hedge for developers against cannibalisation risk. Whilst the risk can be shared between the counterparties, a larger part of it is usually borne by the offtaker to minimise the impact on the cost of capital and make the project viable. For PPAs with intermediaries as offtakers, it is common for the intermediary to take on the full cannibalisation risk (e.g., by offering a fixed-price, pay-as produced PPA contract), as they can manage that risk through trading strategies. PPAs can also facilitate the development of innovative solutions combining renewable assets with energy storage, which can help counterparties manage cannibalisation risk and more generally, support system operation.

Over time, the evolving needs of consumers and producers will ultimately determine the future role for PPAs. This is the key benefit of market-based instruments – they are flexible and evolve in line with the changing needs of producers and consumers. However, we urge the Government to ensure the regulatory and policy environment exists to support their use.

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

In principle, there is no limitation on the range of counterparties that could be a party to a renewable PPA. In reality, however, the most likely candidates on the offtake side would be larger corporate and industrial consumers with sufficient creditworthiness.

Smaller businesses may struggle to meet credit risk requirements and may not have sufficiently large demand volumes. The following instruments could be helpful to support smaller businesses in accessing PPAs:

- A framework for credit guarantees; and
- Aggregation services which can be used to aggregate both demand and supply. These are already offered by a number of utilities and traders. Addressing credit issues could help to broaden their use (as intermediaries can take on only limited counterparty risk).

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

Yes, we agree with DESNZ's decision to focus on a cross-cutting approach for incentivising electricity demand reduction.

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.

To the extent that Contracts for Difference (CfD) continue to be needed to de-risk investment in intermittent renewables, we agree that they should be reformed to incentivise merchant-like behaviour, particularly forwards-hedging.

We agree that the challenges set out by DESNZ remain relevant for the future development of the CfD scheme and deployment of renewables. Going forward, price cannibalisation and volume risk will have a growing impact as prices during periods of high renewables output continue to fall. Such distortions reduce the effectiveness of the CfD scheme as a risk mitigation tool, and risk it becoming a measure which only looks to make up the difference between market revenues and revenues required to make asset construction economic. As discussed in our response to question 1, PPAs also provide a market-led (and in our view, a preferable) opportunity to manage these risks.

For clarity, it would be helpful if DESNZ could rank the challenges in order of priority to help assess future CfD reform options.

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?

Where the distortions that DESNZ has identified are removed, the key difference we would expect to see would be with regards to hedging, where we anticipate a 'merchant' generator fully exposed to market signals would face stronger incentives to forward trade. For other distortions, the difference between a 'merchant' generator and a generator under the existing CfD arrangements is less clear. We consider each area in turn below.

a) Dispatch

The design of the current CfD scheme can distort incentives for efficient market behaviour, most notably in the intraday and balancing timeframes. For instance, when the outcome of day-ahead clearing indicates that a generator will be topped up to the strike price (i.e., the reference price is below the strike price; low but not negative), the generator is still incentivised to maximise production even if subsequent intraday prices go negative (and below short-run marginal costs). Such distortions could have a considerable impact in the future if growing volumes of renewable generation lack incentives to respond efficiently to market signals and system needs.

Merchant generators are incentivised to optimise trading to reduce market risk in response to market signals and system needs. They would seek to maximise revenue from generation and therefore generate as much as possible when prices are above their marginal cost (zero for some technologies).

b) Location

We would expect a merchant operator to respond to locational price signals in a similar way to an existing CfD operator. For both merchant and CfD operators, key asset locational considerations include potential load factors, the availability of land and planning consent, the charge to connect when first developed, and TNUoS charges likely to be faced on an ongoing basis.[19] Both merchant and CfD operators would be incentivised to site assets where these costs are lowest, and where availability of resources (such as wind and irradiation) is likely to be high.

c) Storage and Flexibility

We agree with DESNZ that there is no significant distortive impact to the signals arising from the current CfD scheme. This is particularly the case once the reforms on hybrid metering have been implemented, allowing CfD generators to measure metered output at a sub-balancing mechanism unit level, which may reduce barriers to co-location with other assets such as battery storage.

d) Trading

Were CfD generators exposed to the full range of market signals, we would expect to see more renewable generation traded beyond the day-ahead market. This is because the current CfD disincentives producers from forward hedging or managing a wider production portfolio because they are effectively guaranteed a set price while generating, removing any price risk.

This leads to negative electricity consumer outcomes, as consumers have more choice if power is traded across a range of different time frames (beyond just the day-ahead market), thus providing the possibility for smoothing out movements in volatile prices. This is beneficial to consumers, given most want to see stable unit prices over longer periods. However, the current CfD design increases the cost of providing hedges, because there is less liquidity in the market. This either means higher bills, or circumstances whereby consumers can only reduce bills by being exposed to real time prices.

This is outlined in the report by NERA,[20] which we have attached to our consultation response. NERA's report found that merchant generators would not experience the same distortive incentives as CfD generators as currently designed. Under existing arrangements CfD generators are already 'hedged' against the spot market, which provides a strong disincentive to trade in the forward market.

e) Alternative Use and Project Characteristics

Were CfD generators exposed to the full range of market signals, we would expect them to provide more ancillary services. Currently, generators, including those using a CfD, are capable of offering a range of ancillary services to the system operator, with the correct equipment installed. For example, wind generators can potentially provide fast frequency

[19] TNUOS is also difficult to predict and Mod CMP413 is being discussed on this topic.
[20] NERA (2024) The Evolution of the Cost of Hedging Under the Current Default Tariff Cap Methodology

response services, while other technologies applicable for a CfD such as solar[21] and biomass can also provide system restoration services.

However, during periods where the day-ahead price is above zero, CfD generators are not incentivised to provide ancillary services unless the benefits exceed the net revenues earned via the CfD mechanism. This is because the current CfD allocation process emphasises cost reduction and rewards production of MWh rather than ancillary services.

In general, there may be a benefit to providing a stronger steer to generators as to what services are needed and incentivising CfD generators to provide such services where it is efficient for them to do so.

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)?

We have considered the two "ongoing" CfD reforms described in the document. We agree with the potential benefits of hybrid metering, namely in contributing to reducing barriers for potential co-location of assets. However, we do not support the proposal to expand the scope of the CfD to repowering of existing sites.

As we have previously outlined to DESNZ,[22] we do not believe the CfD is an appropriate mechanism through which to support intermittent renewable assets that have previously had a consumer subsidy. Market forces should be left alone to decide the most efficient use of these sites in the future.

Well-sited renewable generation assets would have significant demand for subsidy-free construction, due to existing factors such as topography, existing grid connections, community support and operating experience. They are therefore likely to be among the lowest cost and highest value opportunities for renewable generation compared to both other low carbon generation and conventional fossil fuel technologies. We therefore expect that there will be demand for subsidy-free construction at these sites irrespective of a subsidy mechanism.

If the market was left to decide the best use of grid connection points, we would expect to see multiple technologies on the same grid connection point – such as colocation solar and battery. This kind of innovation is disincentivised if a CfD is available.

It is also not clear if repowering would usefully increase deployment of capital as indicated in the consultation. Rather there is a risk it would lead to inefficient allocation of capital and further embed existing distortions caused by the current CfD as identified by DESNZ for question 5.

[21] ESO (2024) Distributed ReStart - ESO is trialling the rollout of restoration services to wind and solar
[22] DESNZ (2024) Contracts for Difference for Low Carbon Electricity Generation: Consultation on proposed amendments for Allocation Round 7 and future rounds – Centrica response 07 March 2024

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.

We agree that the deemed approach may give rise to specific and material gaming risks regarding how the deemed output is determined. This is, to some degree, inherent in any approach that completely separates revenues from production. In addition to deliberate gaming, varying complexity of the different methodologies for determining deemed values may introduce an administrative burden or element of additional risk for operators.

Specific opportunities for gaming could include the possibility of a generator overstating the conditions at a given location in an effort to maximise payments or by misrepresenting potential output in the event of being instructed to reduce production. This is a particular risk for option 2 where both collection of site data and calculation of the deemed output are undertaken by the generator, and to a lesser extent for option 1. As this information may be required on a daily basis, this also has the added risk of presenting more frequent opportunities for gaming, and less opportunity for regulatory scrutiny, as opposed to an approach where output is deemed for a longer time period.

Of the four methodologies DESNZ has set out, we recognise that each may have some merit in addressing gaming risk, particularly where asset owners are not directly responsible for collection of data and relevant calculations, such as is the case for option 3. However, each option to some extent would add either a layer of complexity or costs for generators that will need to be weighed against any benefits of the approach. For example, specific costs would be placed on generators with regards to installation of on-site equipment as is the case for option one. In order to fully evaluate these methodologies, we would need further clarity on what each approach would entail, in particular on the specific data that would be required and methodology DESNZ envisages for translating this to deemed output values.

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.

We would expect developers to reflect anticipated revenues from other markets in their capacity-based bids (i.e., the more revenues they expected from elsewhere, the less £/MW they would bid at auction). Experience in the existing capacity mechanism has reflected this with expected revenues from wholesale energy markets and system services being taken into account. A key advantage of a capacity-based approach is that developers can also anticipate some upside from providing additional value.

To the extent that an upside sharing mechanism is introduced – which we are sceptical of the need for such a mechanism – its calibration will influence auction behaviour. This is because the lower the potential upside for developers, the higher their likely auction bids.

The level at which any floor and ceiling on capacity payments is set will likely be the primary factor influencing bidding behaviour at auction and its success. The auction will need to allow for the minimum amount a developer would require in order to make a bid. If this amount is not reached, there may be no bids as occurred with AR5. We believe further consultation is required on how capacity payments may be set. As part of DESNZ's next steps to this consultation, clarity on the duration of the payments should be provided.

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?

While subsidies have played a key role in ensuring renewable growth, market-based instruments are increasingly feasible and should be encouraged as they effectively allocate risks to the party that is best placed to manage the specific risk type. Government-backing should be applied to technologies that have not yet reached grid parity and where the market is less able to deliver the policy outcome alone.

Completely passing most or all risks on to consumers as in the current CfD scheme, could restrict development due to pressure on the overall budget, given it would likely be reflected in lower Administered Strike Prices.

The design of the current CfD scheme can distort incentives for efficient market behaviour, most notably in the intraday and balancing timeframes. Such distortions could have a considerable impact in the future if growing volumes of renewable generation lack incentives to respond efficiently to market signals and system needs.

As set out in the response to question 10, we believe there is merit in looking to address this through introducing a capacity-based CfD, where the design should incentivise generators to behave as merchant generators in terms of responding to price signals from the market and system needs. This would move a share of the risks from electricity consumers to generators who are better placed to manage their assets' exposure to market signals.

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.

Conceptually our favoured CfD reform option is the capacity payment, by virtue of its relative simplicity. The capacity approach could further support investability if payments are set at the right level. This method may also enable more merchant-like behaviour, specifically efficient trading and forward hedging which would be of overall benefit to consumers. Furthermore, this approach could also be introduced alongside other measures, including carrying forward proposals to reform the existing CfD scheme such as reference price reform (discussed in our answer to question 12), for a limited volume of CfD contracts. As set out in the response to question 8, there is a need for further clarity on how such a capacity-based scheme would work, including the benefit-sharing mechanism put forward by DESNZ.

At this stage we struggle to support the deemed CfD because of its complexity, which may give rise to gaming opportunities that are challenging to mitigate, as DESNZ has identified in the consultation. In addition, there may be unintended distortive effects arising from more fully separating revenue from output, including potential increased volume risk. We also have concerns with the deemed option about linking payments directly to the actions of NESO, which can be opaque.

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

We are supportive of the introduction of partial CfDs. There are clear merits to this approach (which can also be combined with other CfD design options), given they would open up opportunities for PPA growth, thereby reducing distortions to market functioning (the benefits of PPAs are discussed in more detail in our response to question 1).

In fact, there are already examples of projects supported through partial CfDs, and it may be helpful to look at them as a reference. For example, hybrid renewables investments whereby only part of a project is covered by a CfD with the remainder being exposed to the spot market are emerging as a permanent feature in the Australian National Electricity Market (NEM).[23]

The Florence School of Regulation quotes some further examples in their technical report[24] on design and implementation considerations for CfDs. Those include the offshore auctions in the UK (Seareen and Moray West), where each project can define the share of the project that is covered by the CfD scheme vs. the share that is covered by a PPA. There are further examples from Belgium and Denmark. In their position paper on "Sustainable Contracts for Difference Design",[25] ENTSO-E also discusses design options for combinations of CfDs with PPAs.

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.

If the fundamental CfD design remains as is – protection from price risk via a fixed strike price – the reference price should be amended to encourage more forwards hedging. We therefore support exploring the option to reform the CfD reference price, in particular the proposed hybrid reference price design.

The current design removes price risk from producers as they are paid a fixed strike price regardless of the price at which they sell their output in the market. It incentivises generators to sell their output in the Day-Ahead market as the difference with the strike price is settled against Day-Ahead prices (Intermittent Market Reference Price, IMRP).[26]

Partial linking of the reference price to the forward market would incentivise producers to sell part of their output in the forward market, thereby improving forward market liquidity. The

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[23] EPRG Working Paper (2023) Renewable investments in hybridised energy markets: optimising the CfD-merchant revenue mix. Note that: "In the NEM, VRE investors are increasingly taking material exposures to the spot market, a characteristic we will refer to hereafter as 'semi merchant VRE plant'. Of the 19,275MW of plant commitments, at least 3600 MW is exposed to the spot market." In the case of the NEM, a revenue mix comprising 73-78% PPA/CfD coverage and 22-27% merchant plant exposure is identified as viable and a tractable project financing.
[24] Florence School of Regulation (2024) Contracts-for-difference to support renewable energy technologies
[25] ENTSO-E (2024) Sustainable Contracts for Difference (CfD) Design
[26] Chapter 6 of the NERA report considers how reform to the reference price may mitigate increases in the cost of hedging

design should allow for enough flexibility for the market to create liquidity in different products, rather than administratively steering liquidity towards certain products. This is what the retail price cap methodology – currently linked to quarterly products – effectively creates.

At this stage it is important to remain open, look at international examples and carry out a more in-depth assessment. This will enable a better understanding of the potential impacts and the ability of different options to incentivise, in practice, certain types of behaviour by generators. In relation to the reference price reform option, it may be worth considering an annual average Day-Ahead reference price, as introduced in Denmark, and the incentives that could create for offering volumes in the forward market.

The potential impact on basis risk should also be part of a more comprehensive assessment of the option. As a preliminary view, we would not expect a significant impact on uncertainty for producers. In addition, from an overall system efficiency perspective, any such marginal increase in basis risk for producers would be fully offset by the benefits to consumers from improved hedging.

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?

We welcome DESNZ's recognition of the important role that PPAs can play in unlocking investment in subsidy-free renewables. We would like to see the Government take actions to remove barriers to such private investment. Such actions should include ensuring that CfD-type support is only provided where it is demonstrably needed,[27] and developing a framework for credit guarantees to broaden the range of counterparties that are able to access PPAs.

For further details, please see the response to question 1 which sets out how renewable PPAs can play a strong role in helping drive renewables deployment.

[27] E.g., to technologies that have not reached maturity and large-scale, capital-intensive projects.

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?

Centrica agrees that the Capacity Market (CM) should be retained. The CM is needed to ensure that flexible assets with higher running costs and lower running hours – which are critical to the efficient operation of the network - are economic, and therefore available during periods of scarcity.

We therefore support the proposal for an "Optimised Capacity Market" (OCM) with a minimum procurement requirement (minima) for low carbon flexible assets. This will help support the development of new and refurbished low carbon capacity, while ensuring that availability of existing flexible capacity remains commercially viable as running hours decline. Over time, we agree that the low-carbon minima should replace bilaterally negotiated dispatchable power agreements in line with government's long-term objective to consolidate all subsidy arrangements into the OCM.

The challenge for the use of a minima target will be the centralised decision making needed to determine the optimal amount of low carbon capacity to be procured, which will need to balance decarbonisation requirements with the risk of raising the costs of procuring capacity. As identified by DESNZ,[28] setting the low-carbon minima level too low could lead to insufficient low-carbon capacity clearing. Setting the minima too high could lead to excess low-carbon capacity, driving up costs for consumers.

The minima level could also impact the smooth transition from existing generation to low-carbon sources. For example, setting a high minima for low-carbon capacity too soon could lead to a cliff edge drop in carbon emitting capacity before new low-carbon technology is ready to fill the gap. DESNZ should ensure it closely manages the minima allocation as the network moves towards lower carbon flexible generation, to ensure there is the right balance of capacity available at all times.

Further, a minima auction target may also split auction participants between low-carbon and high-carbon procurement, leading to a decrease in auction competition. If technologies are selected with small procurement capacities, there could be significant swings in clearing prices from auction to auction. This would be driven by the supply/demand balance, which is more sensitive when there are smaller procurement volumes available.

Ultimately, much will be dependent on the technology that qualifies for the minima, which DESNZ has not specified. Rather, DESNZ has indicated that its target is for as much long-duration capacity as possible to be "low carbon".[29] The use of "low carbon" suggests some gas blended/CCUS or gas blended/hydrogen capacity might qualify, but the consultation is

[28] Review of Electricity Market Arrangements – Alternative Capacity Market Auction Designs: DESNZ research paper number: 2023/027 (July 2023)
[29] Review of Electricity Market Arrangements: Second Consultation (page 75)

not clear. We therefore ask government to provide more clarity around the structure and operation of a proposed OCM auction, specifically the definition of “low-carbon”. Within this definition we would expect DESNZ to provide clarity on which technology would qualify, including what it means for gas blend mixes. We also request that DESNZ clarifies how the minima as a proportion of overall capacity will evolve over time.

While we have sought to make DESNZ aware of some the perceived risks above, we would note that they are all manageable through effective transition planning and constructive engagement with industry. We look forward to contributing to the design of the OCM as the framework principles become clearer.

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?

Centrica agrees with retaining an Optimised Capacity Market as the continued primary mechanism to ensure security of supply. However, there are several further areas the Government should look to address in this consultation via its market arrangements:

- **Clarity on what these proposals mean for unabated gas:** We note the government’s statement that “a limited amount of new build gas capacity will be required in the immediate term to ensure a secure and reliable system as older plant retires”. However, the proposals as put forward in the consultation are not sufficiently clear on the future of unabated gas. It appears to be implicit in the consultation that the delay to CM emissions limits for new plants will allow new CCGT(s) to get CM contracts. However, there is insufficient detail in the consultation in which to make a full and proper assessment. Specifically, it is not clear that the proposed emissions limits for 2026 will not impact new-build CM plant for the duration of their 15-year contracts. Given the need to provide long-term investment and revenue certainty, we request that the government provide clarity around its intentions for both new build and existing unabated gas capacity.
- **Battery de-rating factor:** The CM is not currently designed to award contracts to lower carbon intensity assets like batteries and pumped storage. This results in batteries being under-valued in the CM with a significantly higher de-rating factors compared to other technologies, hampering their deployment, despite being a flexible technology. Such technologies should have a lower de-rating factor to reflect their flexibility.
- **Extended Performance Test (EPT):** Battery Capacity Market Units (CMUs) are the only units required to undertake Extended Performance Tests to ensure that they can meet their CM obligations, which has had a negative impact on their business cases. This, as well as very low derating factors put battery storage units at a disadvantage and prevents them from opting for longer duration contracts. If the government intends to facilitate more investment in low carbon capacity through the CM, there needs to be some consideration around the barriers these types of assets face in the current mechanism. We would support the EPT being based on the CMU’s Net Capacity

Obligation rather than on Adjusted Connection Capacity. That way, storage capacity will align with actual performance, which will degrade over time.

- **Hydrogen to Power:** The CM still requires certain updates to be fully compatible with H2P. For example, an exact definition / technology class for hydrogen in the CM should be included as soon as possible, and details provided as to how specific methodologies will be applied, such as the calculation of de-rating factors, for both 100% H2P and variable hydrogen blenders.

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?

We welcome the Government's ambition to align the OCM with the decarbonisation of generation. We support Government long-term phasing out of OCM support for new build 'high' carbon assets. We believe the move to introduce lower emissions limits for new and refurbishing CMUs by 2034 for contracts awarded after 2026 will deliver this objective.

We are, however, concerned that some uncertainty remains regarding the timescales for the rollout of low-carbon technology, the economic case for converting existing plant and how current generation will be treated in the CM. It is therefore difficult to say with certainty whether the emission limits proposed in auctions from 2026 is set at the right level for when it comes into force in 2034. Specifically, we are concerned that the yearly limit of 350kgCO2/kW may materially decrease gas peakers' running hours – despite efficiency improvements – impacting their commercial viability. If these plants were restricted from accessing the CM, it could lead to a potential capacity cliff edge in later years if low-carbon generation is not yet ready to fill the gap. We would urge government to work closely with industry to ensure any future emission limit is at the right level before it is put in place.

Further, we note that government has sought to balance proposing emission limits in the OCM to incentivise lower carbon capacity, while also ensuring a limited amount of new gas capacity is brought online in the coming years while alternative low carbon capacity is developed. As laid out in question 15, the Government has not been clear on how new emission limits will impact unabated gas. While it appears to be implicit in the consultation that the delay to CM emissions limits for new plants will allow new CCGT(s) to get CM contracts, it is not clear whether the emissions limits will have an impact on new-build CM plant for the duration of their 15-year contracts. We therefore ask the government to provide clarity.

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?

As outlined above, while we support the lowering of emission limits for new build and refurbishing capacity, we would urge government to consider whether the yearly limit of 350kgCO2/kW is at the right level.

Government has suggested in the consultation that a yearly limit of 350kgCO2/kW would allow 750 hours run time (based on an unabated gas peaker plant that is 40% thermally efficient emitting approximately 460gCO2/KWh). However, a yearly emissions limit of 350kgCO2/kW would require a significant hour runtime reduction in current peaking plants, even with relatively modern designs. Given this limited available runtime by 2034, this may significantly undermine any future business case to support new build gas peakers, as these assets would be effectively excluded from the capacity market impacting their commercial viability.

We are concerned that setting the limit at the wrong level now may not create the right investment conditions for additional unabated gas to be built, if there is uncertainty over their ability to meet future 2034 emission limits. This could in turn risk a cliff edge drop in flexible capacity on the system in later years, as aging plants retire without low carbon alternatives ready to fill the gap. However, given the long time horizon, it's very difficult to say with any certainty at this time. We would urge government to properly engage with industry on the appropriate annual emission limit to ensure that essential capacity is not risked in later years.

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

We are broadly supportive of the policies that are already in place or in development. The following challenges remain in converting existing unabated gas plants to low-carbon alternatives:

- **Locational factors:** Certain low carbon flexible technologies, such as hydrogen to power (H2P), will face significant challenges in accessing transport and storage infrastructure dependant on their location. This may restrict the ability of some unabated gas plants to convert, even if substantial support mechanisms are in place. This will likely only be solved once the economy and infrastructure has developed further to allow their conversion. We need to see more certainty on the ambition and timeline for key infrastructure like hydrogen transport and storage to support H2P plants. As stressed in our response to DESNZ consultation on the market intervention need for hydrogen to power,[30] hydrogen transport and storage will be vital for peakers and CCGTs that will operate at lower capacity factors. Equally it will be critical for smaller distributed, behind the meter CHP that will require baseload hydrogen supply.
- **Clarity on business models and regulatory certainty:** Large-scale, low-carbon flexible technologies are still in their early stages. In many cases, the Government has only just introduced or is in the process of introducing business models to support investment in specific technologies. Some uncertainty therefore remains regarding their implementation and long term operations. As a consequence, it may be difficult for unabated gas assets to plan exactly how they might convert in the future due to this continuing uncertainty. This may act as a barrier to the development of new unabated gas generation.

[30] Centrica's response: Hydrogen to Power: Consultation on the Need, and Design, for a Hydrogen to Power Market Intervention (Feb 2024)

- **Fuel availability:** Fuel availability will remain a challenge for some low carbon alternatives, especially for H2P plant, particularly in the early 2030s where hydrogen markets are localised with finite production. This is particularly concerning for H2P using green hydrogen as it will be contingent on weather conditions and/or sufficient availability of hydrogen storage. Similar to locations, this will likely restrict some plants ability to convert irrespective of support mechanisms.

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.

We agree that current or proposed bespoke support schemes do provide a viable investment landscape for existing unabated gas to convert to low carbon alternatives. These include the DPA for Power CCUS, the proposed DPA for H2P and proposals such as CM managed exits and enabling H2P and Power CCUS participation in the CM. These support mechanisms are important, as the CM alone will not be sufficient to drive the necessary investment in transitional technologies.

However, these technologies and support mechanisms remain at very early stages of development. In many cases, the Government has only just introduced or is in the process of introducing business models. It is therefore difficult to predict with any certainty how successful these mechanisms as a broad package will be in supporting existing unabated gas to convert in the future, as outlined in our response to question 18.

As highlighted above, H2P will be heavily dependent on access to large underground hydrogen storage being available. The viability of H2P from green hydrogen, in particular, is highly sensitive to the availability of hydrogen storage. Strategic planning and joined-up thinking is required between Government departments to ensure the timing of and procurement ambition of critical infrastructure and hydrogen to power plants is fully coordinated and matched.

Large scale energy infrastructure projects such as geological hydrogen storage and hydrogen pipelines have much longer lead times than the construction of any given H2P asset. Decisions must be made as soon as possible as to the cross-chain infrastructure necessary to facilitate this, otherwise H2P assets risk becoming delayed, stranded, cancelled, or forced to run as unabated gas generation due to a lack of access to hydrogen fuel. We would encourage Government to accelerate its timelines and ambitions on the development of hydrogen networks and storage whilst removing development barriers.

Finally, as outlined in response to question 17, while we support the intention of proposed emissions limit reductions, it is too early to predict the impact these will have on the economic case for new or refurbished gas peakers, as there remains too many uncertainties around their future runtimes and ability to reduce emissions in line with the proposals put forward.

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.

Centrica agrees that retaining an Optimised Capacity Market (OCM) as the GB capacity adequacy mechanism will allow domestic scale, aggregated Demand Side Response (DSR) to participate in capacity auctions on a competitive basis.

However, investment in domestic scale Low Carbon Technologies (LCTs) to provide DSR is unlikely to be driven by the OCM alone because domestic consumers tend to make decisions on whether to invest in such technologies based on the overall level of reward they can expect through providing DSR across several flexibility markets. Because of this, the ability for Flexibility Service Providers, which aggregate, optimise, and dispatch DSR on behalf of their customers, to access multiple revenue streams using the same assets will be critical to providing the level of reward expected by consumers, and therefore to bringing forward the levels of short duration flexibility required by 2035 that are set out in the consultation document.

The consultation correctly identifies the main challenges faced by domestic-scale DSR, including some of the barriers to participating in several flexibility markets, inefficient market operations, and the need for sharper operational signals.

While we broadly agree with the initiatives set out in Appendix 3, we would highlight the following:

a) The importance of value stacking to domestic consumers

The ability to access and stack value across multiple flexibility markets is essential. However, the approach currently being taken by network operators is unlikely to deliver the level of value-stacking needed to encourage consumers to invest in flexible LCTs. For example, the Electricity Networks Association's (ENA's) Open Networks (ON) programme is being run separately to the strategic workstreams being led by Ofgem which is resulting in some key issues receiving insufficient attention, such as the alignment of delivery periods between network operators, services, and products.

The ON programme would also benefit from increased regulatory backing to drive the required changes to completion. We urge government to work with Ofgem to take a more active role in ensuring that the multiple initiatives underway and planned are better coordinated to ensure that the future markets for DSR are better managed, with more emphasis placed on providing consistency around how barriers to market access and efficient participation are addressed.

b) The need to redefine metering standards for domestic-scale DSR

One of the main barriers to participating in several flexibility markets, most notably those operated by the National Grid Electricity System Operator (ESO) is excessively stringent operational and performance metering requirements. This is not mentioned in the consultation document at all. The requirements for metering accuracy and read frequency were defined when flexibility was predominantly provided by large, dispatchable generating plant. These standards are not appropriate for small-scale distributed flexibility assets such as an Electric Vehicle Charger, or electric heating system, given the additional costs they impose on LCT manufacturers, reducing the financial case for investing in them.

The work being done under ESO Power Responsive programme has made a good start on relaxing operational metering standards, and we will continue to support that programme with its ongoing trial to assess the impact of relaxing metering standards for small-scale DSR assets. However, we consider that the approach to this issue should evolve toward focussing on the level of operational metering accuracy required at an aggregate level, rather than on a per asset basis. The Power Responsive programme is overseeing an independent review of what the ESO control room needs to monitor and dispatch domestic-scale DSR, and we will continue to work with it on this topic.

It will also be important to ensure that metering standards are aligned between the local (Distribution) and national (Transmission) flexibility markets will support DSR assets participating in both sets of markets simultaneously and ensuring that assets which provide a benefit to the electricity system at both levels is rewarded accordingly. We ask the policy makers and the energy regulator drive the changes to the national and regional domestic flexibility markets needed to ensure that the full potential of low carbon technologies is realised.

An area where intervention by the Government may be required is to resolve conflicts for metering standards which are set out in secondary legislation. Metering standards for asset-level metering currently fall under several sets of rules, including those set out in the Measuring Instruments Regulations 2016 (MIR) and The Electric Vehicle (Smart Charge Points) Regulations 2021 (EVSCPR). The MIR contains requirements that asset-level meters must meet to be used for trading purposes which are not reflected in the EVSCPR. This is resulting in EV Smart Charge Points being manufactured and installed which cannot be used to trade directly in the flexibility markets, which reduces the value that can be realised using the asset.

We ask that this issue is addressed as soon as possible, and that any similar conflicts are avoided when asset-level metering regulations are being considered for other flexible low carbon technologies in the future.

c) Improving baselining methodologies for DSR

We agree that the consultation correctly identifies the importance of defining appropriate baselining standards for domestic DSR, as well as the need to establish aligned baselining methodologies across all flexibility markets. We would also highlight that work on improving baselines must include the Distribution System Operators (DSOs) as well as NGESO to ensure that a consistent set of standards is applied across all flexibility markets.

We would also highlight that domestic DSR installations are likely to become increasingly complex in the future, incorporating several complimentary LCT technologies such as Solar Photovoltaic panels, batteries, EVs and other smart appliances to provide flexibility to the markets whilst also optimising within-home power usage. The baselining methodology adopted must be capable of accommodating the complexities which accompany such installations.

d) Standardisation and simplification of markets to improve revenue stacking

The consultation document correctly identifies the need to standardise flexibility service products, procurement and operational processes, and settlement across the DSO markets. However, the work it highlights being done by industry under the Open Networks (ON) programme has been slow to deliver the required reforms, and it is becoming apparent that the programme may lack the powers to bring the DSOs into sufficient alignment to support the levels of participation needed. Whilst the forthcoming Market Facilitator (MF) body should have increased regulatory powers to drive full alignment, there seems to be a gap between what the ON programme will be able to achieve during 2024, and when the MF is due to go-live at the end of 2025.

We consider that more is needed to unlock full value stacking than the work being done by the ON programme on DSO alignment and the introduction of Primacy Rules. Along with aligning procurement timescales, for example the introduction of Day-Ahead trading, delivery windows also need to be aligned to allow full value stacking. Some flexibility markets require delivery by Settlement Period, whilst others require delivery by Electricity Forward Agreement (EFA) blocks, with some markets using a different delivery period again. Alignment of delivery periods will allow FSPs to utilise several different revenue stacking strategies and will help to unlock the full value of each MW of the flexibility that can be provided by domestic DSR for consumers to benefit from.

We would highlight that the development of effective local flexibility markets depends on the role of network operators being clearly defined. We have seen the most progress in the areas where Ofgem or Government gave the regulated networks clear direction on what was needed to facilitate the development of flexibility markets. The clearest example of this is Ofgem's Data Best Practice Guidance and the associated licence conditions. This resulted in significant improvements in availability and standardisation in time for the start of RIIO-ED2.

Conversely, where Ofgem was not clear on what DNOs had to deliver to ensure neutral DSO functionality and facilitate the development of robust flexibility markets, we have seen slower progress and even signs of further divergence.

Furthermore, have concerns that some DSOs have expressed a strong interest in developing flexibility products or services which would allow them to procure flexibility services directly from consumers, without the involvement of a supplier or Flexibility Service Provider (FSP). We expect the regulated networks to continue to work through the market to access consumer flexibility and not procure services directly from households, which risks fragmenting the market and could result in confusion amongst consumers.

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.

Broadly yes, provided that “sharper operational signals” includes improving the efficiency of the Balancing Mechanism (BM) by reducing skip rates, reducing barriers to DSR, and improving the technical and operational capabilities of the system operator. We provide detailed views on opportunities to improve temporal signals in response to question 24.

While we agree in principle with including low-carbon minima in an Optimised CM to incentivise low-carbon flexibility, we would urge government to provide more clarity around the structure and operation of a minima auction i.e. which technology would quality, what it means for CCGT and gas blend mixes access to the CM and how the minima as a proportion of overall capacity will evolve over time.

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

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

We urge DESNZ to reject zonal wholesale pricing as a reform option. Beyond perhaps improving the dispatch efficiency of interconnectors, we do not agree with the qualitative benefits case for zonal as articulated in LCP Delta's ("LCP") modelling for DESNZ, let alone the quantitative. We believe that the costs of introducing zonal wholesale pricing will easily outweigh any purported benefits.

Furthermore, the "demand exposure" part of the assessment of design options in Appendix 4 should include compatibility with the price cap that is currently applied to residential energy default tariffs. We support simplification and continuation of that p/kWh price cap, including through the removal of the standing charge and abolition of regional price variations for all residential customers.

We continue to urge the Government to ensure that wholesale electricity market reforms are complementary to – and at least compatible with – the retail electricity market. As we have shown previously, it is difficult to justify supporting both a retail price cap and locational wholesale pricing where demand is exposed to the locational price. DESNZ's "Future default tariffs: call for evidence," published in February this year,[31] does not mention REMA. Nor does this REMA consultation mention the "Future default tariffs: call for evidence." These reform programmes need to be joined up urgently and explicitly. Holistic thinking is needed to deliver an electricity market design that best protects current and future consumers.

In the rest of our response to this question, we discuss:

a) Why LCP's benefits case for zonal is not convincing;
b) Some important costs and risks of implementing zonal wholesale pricing; and
c) Key considerations should zonal pricing be implemented

a) Why LCP Delta's benefits case for zonal is not convincing

LCP suggest that constraint costs effectively transfer from generator payments to consumer savings in a zonal market. LCP also suggest that significantly more onshore wind locates in the North of Scotland under a zonal compared to a national market. We do not believe it is plausible that such additional volumes of generation will locate in Scotland if they are exposed to the zonal price. Generator revenues from today's constraint payments are likely to need to continue or be replaced in some way to guarantee construction of sufficient renewables capacity to meet net zero.

[31] DESNZ (2024). Future default tariffs

There are also striking differences between the results of LCP's analysis for DESNZ and FTI's analysis for Ofgem. For example:

- LCP predict that batteries will relocate away from Scotland following the introduction of zonal wholesale pricing whereas FTI suggests that they will relocate into Scotland; and
- LCP predict that solar farms will relocate away from the southernmost zone of England following the introduction of zonal wholesale pricing whereas FTI suggest they will relocate into it.

These striking differences demonstrate how difficult it is to confidently predict any benefits of zonal wholesale pricing and how sensitive the findings are to assumptions. The difference in findings between the two studies also demonstrates the uncertainty that such reforms would create for potential investors in new generation assets – and is a good illustration of the chilling effect such reforms will subsequently have on investments that are of critical importance to achieving net zero.

In addition, LCP's assessment of zonal does not consider the impact of zonal wholesale pricing on existing or new nuclear power stations. Sizewell B is currently anticipated to continue generating until 2035, with the potential to extend by 20 years to 2055, if economically viable.[32] Moving to zonal wholesale pricing would have implications for the economics of nuclear assets that are not insulated from the zonal price by either a CfD or a Regulated Asset Base (RAB) support model. Zonal wholesale pricing may also affect the functioning of CfD and RAB based support for nuclear assets via the reference price.

b) Important costs and risks of implementing zonal wholesale pricing

i) Negative impact on forward market liquidity

LCP's assessment does not quantify the upward pressure on consumer prices of the reduction in forward market liquidity that would result from the introduction of zonal pricing. To the extent that DESNZ continue to consider zonal pricing as a reform option, they should seek to quantify the impact of the reduction in market liquidity on consumers and use empirical evidence to inform that assessment. As part of the assessment, we strongly encourage DESNZ to explore international examples of zonal reconfigurations, e.g., in Sweden and Italy, and the related impact on liquidity, retail competition, investment in renewables and constraint costs.

Splitting the GB market into zones would reduce forward market liquidity even further compared to today's already poor levels. This means that it would be very difficult for retail suppliers to manage their load books and for businesses to hedge their energy consumption, increasing exposure to price volatility and impacting businesses' competitiveness. Lack of liquidity also increases investment uncertainty (e.g., investment in renewable energy, but also

[32] EDF (2024) UK Nuclear Fleet stakeholder update Executive Summary states: "The focus for the Sizewell B power station is on operational excellence and investing to enable a potential 20-year life extension, out to 2055. This decision is subject to agreeing the appropriate commercial model to ensure such an extension is viable".

in other types of assets and in industrial demand sites) due to the increased difficulty of predicting and managing future revenues and costs.

Lessons from zonal splits in other markets indicate that liquidity could drop significantly. The Swedish zonal split in 2011 led to a -42% loss in Swedish Electricity Price Area Differentials (EPADs) market liquidity.[33] Reduction in liquidity translates into costs to consumers due to hedging becoming more difficult and expensive. In the example of the Germany/Austria zone split, Energy Traders Europe (previously EFET) report a 1-2 EUR/MWh increase in the bid-ask spread in the Austrian zone (the smaller zone being split form the much larger German zone).[34] In the UK context, with consumption in the range of 300 TWh per year, a comparable increase in the bid-ask spread could lead to costs to consumers of £300-600 million.

A zonal split would also reduce competition, as there would be fewer market participants in each zone. This means a potential increase in market concentration and market power, which come at a cost to market efficiency and consumers.

ii) High risk of damage to investor confidence

Centrica has ambitions to deploy significant amounts of capital in the UK energy system, helping to drive the green transition. As investors have emphasised throughout the REMA process, there is a link between regulatory certainty and confidence to deploy capital in the UK. Centrica is not averse to change if it is in the interests of consumers; indeed, we have actively advocated for energy market reform in a number of areas. However, in order to justify fundamental reform, a high threshold must be satisfied to show that it will deliver significant benefits to consumers in practice as well as in theory. This threshold is naturally higher at this stage in the transition to net zero, when such significant investment in new energy infrastructure is urgently needed.

As we have laid out, we do not consider that this threshold has been met by the evidence put forward to justify a move to zonal pricing. For example, the striking differences between the results of LCP's analysis for DESNZ and FTI's analysis for Ofgem demonstrate how difficult it is to confidently predict any benefits of zonal wholesale pricing and how sensitive the findings are to assumptions.

The difference in findings also demonstrates the uncertainty that such reforms would create for potential investors in new generation assets – and is a good illustration of the chilling effect such reforms will subsequently have on investments that are of critical importance to achieving net zero. We therefore do not believe that any theoretical benefits of introducing zonal pricing would be worth the uncertainty and disruption it would cause to investment confidence. We strongly urge DESNZ to focus all available resources on enabling grid investment and swift connections for projects that are ready.

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[33] EFET (2019) Bidding zones delineation in Europe: Lessons from the past & recommendations for the future; (2016) A reality check on the market impact of splitting bidding zones

[34] EFET (2019). Bidding zones delineation in Europe: Lessons from the past & recommendations for the future

LCP also found that an increase of 0.3 to 0.9% in cost of capital would remove the perceived benefits of a zonal market, while an increase of 1% would reverse the benefits. While the impact on costs of capital is difficult to predict, the consultation document quotes external estimates of little (0-1%) to high (3%) impacts on costs of capital. According to LCP's analysis, even staying at the low end of this range (0.3-0.9%) would remove the benefits of zonal pricing, while further increases would actually lead to a net loss for consumers from moving to zonal pricing.

iii) Uncertain impact on investment siting decisions

A perceived benefit of locational pricing is that it leads to generation and demand locating in parts of the network where they would offer most value to the system. However, the extent to which demand or production would relocate in response to zonal pricing is highly uncertain and difficult to model. Neither LCP nor FTI have provided compelling evidence that demand or production act in this way. This is because there are many factors beyond locational wholesale prices that contribute to siting decisions for renewable assets and electricity demand sites. These include permitting, local approvals, natural resource availability and grid connections (including timescale for connection). These all would have a significant impact on the viability of renewable investments.

As illustrated in the table below, most technologies (with the exception of solar and energy storage) are restricted in terms of where they can locate.

Figure 4: Technology Location Restrictions – LCP Delta[35]

Technology	Exposure to TNUoS signal	Exposure to Locational Pricing Signal	Restrictions on zones
Offshore Wind	Full exposure	Exposed to signal but dependent on CfD arrangements	Limits by zone based on seabed availability
Onshore Wind	Assumed 50% of capacity is exposed to TNUoS signal as 50% is distribution connected	Exposed to signal but some capacity dependent on CfD arrangements	Can only build in Scotland and Wales.
Solar	Assumed to be 100% distribution connected so no exposure	Exposed to signal but some capacity dependent on CfD arrangements	No limits
Other Renewables	Assumed location is dictated by other factors so does not change location, e.g.: resource availability		
Nuclear	Assumed locations are fixed as Nuclear sites across the country are limited		
Gas CCS	Full exposure	Full exposure	Limited based on locations of industrial clusters.[35]
Biomass CCS	Assumed location is dictated by other factors so does not change location, e.g.: location of current biomass plants		
Hydrogen	Full exposure	Full exposure	Limited based on locations of industrial clusters[31]
Electrolysers	Full exposure	Full exposure	Limited based on locations of industrial clusters[31] and max of 50% new build in Scotland
Storage	Full exposure	Full exposure	No limits

[35] This is assumed to be all zones except A and H, and zone L before 2035

In its study on the Review of Electricity Market Design in Great Britain,[36] AFRY also draw similar conclusions in relation to the limited ability of locational markets to deliver more efficient siting of generation and demand, particularly longer-term. Instead, according to the analysis, the benefits of locational markets relate particularly to improved dispatch incentives. Further,

[35] LCP Delta / Grant Thornton (2023). System Benefits from Efficient Locational Signals
[36] Afry (2023). Review of electricity market design of Great Britain

Micheal Pollitt, in his assessment of locational wholesale pricing for Ofgem, also concludes that "[T]he proven benefits of nodal pricing are in short run operational dispatch improvements NOT long-run siting decisions".[37]

c) Key considerations should zonal pricing be implemented

If the Government decides to pursue a shift towards zonal pricing, which we do not recommend for the reasons outlined above, then we would urge for a thorough analysis of the benefits and risks of different options, similar to the bidding zone review process carried out in the EU. This is because the smaller the zones, the more acute the problem with hedging complexity will become and the greater the price risk for investors (in clean energy, but also other assets and industrial demand). The risk would also increase for retail domestic and business consumers, who would be more exposed to price volatility, and for corporate and industrial consumers, whose competitiveness may be impacted.

Any subsequent changes to the zones would cause investment uncertainty and should therefore be limited. Reviews, if deemed necessary, should take into account overall welfare and market efficiency impacts, and should not have a narrow focus on congestion (which also seems to be the case in the overall discussion between retaining national pricing and moving to a zonal split).

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.

As outlined above, we find much of the benefits case for zonal wholesale pricing inadequately evidenced. It fails to account for the high risk of damage to investor confidence and the negative impact on forward market liquidity (i.e., costs of hedging), which can undermine the deliverability of the transition in a timely and cost-efficient manner. There is also considerable uncertainty about the impact on investment siting decisions. We nevertheless believe it is possible to strengthen locational investment signals and make dispatch more efficient in an enhanced national wholesale market.

In response to this question (23) we provide our reflections on "Option set 2" outlined on pages 96-101 of the consultation document. We provide our views on options to improve temporal signals in response to question 24 below. Our recommended options for improving temporal signals are compatible and complementary to our views on "Option set 2".

Currently "Options set 2 – Alternatives to locational pricing" includes:

- Using Ofgem's pre-existing network charging reform programme (option A).
- Reviewing Ofgem's transmission network access arrangements (option B).
- Expanding measures for constraint management (option C).

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[37] Michael G. Pollit (2023). Comments on the FTI Report on Assessment of locational wholesale electricity market design options in GB

- Optimising the use of cross-border interconnectors (option D).

Of these, we support Option A, C and D, which are all necessary and help in different ways. We have significant concerns about Option B, which appears to be predominantly about restricting firm grid access rights. Firm access rights are imperative to give a potential investor sufficient certainty to commit to the construction of a generation or storage asset. We can see the theoretical rationale for exploring auctions of connections and/or firm access rights, but we struggle to see how it can work efficiently and fairly in practice. For example, it might be most efficient and fair to give a connection to a ready-to-connect smaller asset before a less ready-to-connect larger asset, but the larger asset may be able to pay more.

On Option A, we would endorse providing clearer, stronger and more predictable locational investment signals through charges applied to generators. We look forward to engaging in the detailed development of this option.

On Option C, we encourage further development and expansion of locational constraint markets to take pressure off the Balancing Mechanism and give flexibility providers more foresight of potential revenues in different locations. A portfolio approach to constraint management through the development of a range of constraint markets covering all relevant timescales would give more flexibility and visibility on available resources to the ESO.[38]

A portfolio approach to constraint management could include tendering for long-term contracts where upfront costs would only cover the availability component; and tendering for short-term – day-ahead (DA) and intraday (ID) - contracts procuring firm response, or availability in DA/ID (aligning with the structure of other ancillary services). Pathfinders and exploratory projects can also be used to assess new solutions and potentially add to the portfolio of constraint markets (e.g., the Local Constraint Market trial launched in Scotland to help manage B6 constraints through the procurement of demand turn up services from assets not participating in the BM).

On Option D, we strongly encourage the UK Government to agree with their counterparts in other Governments to couple interconnected electricity markets. Coupling whould improve the efficiency of interconnector dispatch.

Under the present arrangement between GB and the EU, interconnectors are not integrated efficiently into the GB wholesale power market, which means that electricity traded across borders is not subject to the same market signals as market participants within GB. This can cause additional actions to be required by the system operator to manage congestion within the GB system. We acknowledge the ongoing work of the UK government with the EU to implement the Trade and Cooperation Agreement (TCA) which should deliver improvements to the status quo.

However, the Government should go further and aim for full price coupling to deliver maximum benefits to UK consumers and enable the efficient use of future Offshore Hybrid Assets that will deliver vital benefits to the UK energy system and play a key role in moving to a Net Zero

[38] TEL (2024) Exploring options for constraint management in the GB electricity system

economy. Energy UK found that greater cooperation with the EU on issues like energy trading and carbon pricing has the potential to lower energy costs for the UK economy by up to £1.1.billion per year.[39]

We urge Government to accelerate ongoing and planned improvements under the TCA and other working groups, including:

- Re-sharing of order books in Day-Ahead (DA) to reduce operational complexity.
- Implementing Forward, Day-Ahead and Intraday trading across all existing and future interconnectors to ensure that interconnectors can deliver maximum flexibility in response to evolving system needs.
- Introducing mechanisms for the exchange of balancing products between the UK and the EU by building on the work launched by the ESO on cross-border balancing market design[40] to allow interconnectors to provide flexibility in the balancing timeframe.
- Ensuring that the EU Carbon Border Adjustment Mechanism (CBAM) does not distort cross-border trading by facilitating effective accounting for the carbon price paid in the UK and taking into consideration the evolving electricity mix in the UK.[41]
- (Re-)introducing efficient trading arrangements for the operation of interconnectors. Implicit trading ensures optimised capacity allocation and cross-border flows. This is also confirmed by Ofgem in their consultation on Market Arrangements for Multi-Purpose Interconnectors,[42] where implicit capacity allocation, together with introducing offshore bidding zones, is highlighted as the most efficient solution for the market integration of Offshore Hybrid Assets.

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 believe there are a number of opportunities to improve temporal signals in an enhanced national market. In particular, the future National Energy System Operator (NESO) should continue to improve the efficiency of the Balancing Mechanism (BM) by reducing skip rates, reducing barriers to DSR participation, and enhancing its technical and operational capabilities. We do not support the introduction of central dispatch and do not believe that <u>any</u> benefits of introducing central dispatch could outweigh the profound uncertainty and widespread disruption that such an intervention would create.

a) Improving the capabilities of the ESO

Urgent improvements are required to digitalisation, IT investment, and Control Room processes to enable the ESO to meet the challenge of operating a system based on distributed renewable and low-carbon flexibility resources.

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[39] EnergyUK (2023) Why heightened engagement is imperative for Net Zero
[40] ESO (2023). Study on Cross-Border Balancing Market Design
[41] AFRY (2024) AFRY study shows how the EU CBAM could jeopardise North Sea offshore grid infrastructure
[42] Ofgem (2023). Market Arrangements for Multi-Purpose Interconnectors

We welcome the steps that the ESO has already taken in this area. It has launched the Open Balancing Platform (OBP) and has started the transition away from its legacy system for balancing and ancillary services. We also note the introduction of bulk dispatch for batteries and small Balancing Mechanism Units (BMUs) over the automated OBP, the move to a '30 min rule' for the dispatch of batteries, and the planned introduction of new dynamic parameters for limited-duration assets in the Grid Code, which would enable the ESO to dispatch batteries more efficiently.

These changes will enable the ESO to utilise more effectively smaller, distributed resources, which currently are severely underutilised. This is especially the case for battery assets which are being "skipped" in the BM despite appearing to be in merit (battery skip rates of 91% in the summer of 2023).[43]

b) Improving information sharing and accuracy

Improved information sharing between market participants and the ESO is required to provide accurate and complete data for optimisation processes. To do this, the ESO needs to define the information it requires from market participants for improved operational efficiency.

We recognise the ESO faces difficulties managing increased updates to physical notifications from generators in the hours before delivery, and an increased number of generators participating in the system. While such changes are to a large extent a function of the changing electricity mix and the growth in intermittent generation, we believe there is room for improvement, and we would be happy to engage with the industry in examining this challenge more closely.

In addition, improvements in forecasting supply and demand are required. A future renewables-based system will see supply increasingly dependent on changes in weather, while demand will become difficult to predict (e.g., from EVs). Improved forecasting tools and close ESO-DNO cooperation will be crucial in enabling the ESO to effectively manage the changing demands of the system.

Benchmarking and learning from other system operators could also be helpful with forecasting. The example of the Danish transmission system operator,[44] running a power system with a large share of intermittent renewables, shows that a strong focus on improvements in forecasting can help to reduce renewables curtailment.

c) Improving competition in the Balancing Mechanism and ancillary services

Improved competition is essential for decreasing the costs of system balancing and stability, as well as reducing the carbon footprint of the BM. It can be delivered through:

- Improving dispatch of assets already participating in the BM (e.g., batteries and small BMUs); and

[43] MODO (2023) Balancing Mechanism battery energy storage skip rate is 91% | Modo Energy; The ESO has also commissioned a study on skip rates, which should provide evidence on how the situation is evolving, but we understand the study has been delayed.
[44] Danish Ministry of Climate, Energy and Utilities (2020) Fact sheet

- Broadening the number and range of market participants in the BM (e.g., by facilitating the participation of demand-side response).

The former requires improving the technical capabilities of the ESO to dispatch batteries and smaller units, as discussed above, while the latter requires assessing and removing barriers to entry. There are barriers to entry for small-scale distributed assets (e.g., EV chargers and electric heating systems) such as metering requirements, MW integer increments for participation, and relatively slow lead-times for registering and updating BMUs, which need addressed.

The current requirements for operational metering, for instance, are not proportional to the impact of each domestic scale DSR asset. The ESO balances the system at BMU level. This requires accuracy at BMU level and means that high level of data accuracy at the individual asset level is not essential for the system operator. At the same time, such requirements add significant cost to such DSR assets that could inhibit the uptake of flexible low carbon technologies by domestic consumers. Trials, such as the ESO-led Power Responsive trial, offer an efficient way of testing possible solutions to facilitate market entry for a wider range of market participants, without compromising on system security.

There are further barriers to entry to the BM for flexibility service providers (FSPs) with less than 1 MW of DSR capacity. It is currently difficult for FSPs to achieve the required 1MW minimum threshold for participation in the BM, particularly when the usage patterns of domestic scale DSR assets are considered. The requirement to submit Bids and Offers in 1 MW increments also mean that any assets that fall between two MW integers are unable to participate and are wasted.

d) Streamlining products and developing markets

Improvements to the design of products and services can strengthen the ability of the ESO to respond to system needs close to real time and plan ahead. In combination with IT development to improve operational efficiency, it would help the ESO to better manage the increasing complexity of balancing and ancillary services.

The ongoing Balancing Programme [45] was set up for the purposes of reviewing and streamlining the variety of products and services that currently comprise the GB Balancing Mechanism and ancillary services. It offers a good foundation on which to build further improvements. These should include:

- Timely implementation of the Market Roadmap, as so far there have been frequent delays;
- Further gap analysis carried out by the ESO to identify additional needs;
- Development of product parameters in consultation with market participants; and
- Further development of markets.

[45] ESO Markets Roadmap (2024) Markets Roadmap

e) Granular certificates

Granular certificates,[46] not covered in the consultation document, are another mechanism for improving temporal signals. They are a market-based instrument for the temporal matching of renewable energy supply and demand. Greater granularity can be built into existing guarantee of origin schemes (i.e., the Renewable Energy Guarantees of Origin (REGOs) in the UK) by incorporating e.g., an hourly timestamp that can be used on a voluntary basis by market participants to account for the exact temporal matching of their electricity consumption with renewable energy production.

With the growth in corporate sustainability targets and commitments, and increasing calls for more accurate carbon accounting, demand for granular certificates may grow in the future, including in relation to green hydrogen production. By creating a signal for a temporal match between renewable energy consumption and production, they create incentives for innovation and the uptake of storage and other solutions that can help producers and consumers ensure this temporal match. This can help to reduce the need for the ESO to take balancing actions. This mechanism is worth exploring and developing further, as it offers potential for market participants to contribute to reducing the pressures of decarbonisation on grid management.

f) Gate closure

We recommend moving gate closure closer to delivery. In Europe, balancing energy bids can be submitted 25min before delivery and in our view, the ESO can implement, as a minimum, the same improvements. This can be done by amending the ESO's optimisation algorithm and specifically shortening its computation time.

Gate closure set at 60 minutes before delivery prevents market participants from making adjustments closer to real time on the basis of the latest information, which could alleviate some of the pressure on the ESO for close to real time adjustments. In fact, empirical evidence indicates that intraday trading close to real time can have significant benefits in terms of decreasing the demand for balancing energy.[47] Moving gate closure closer to real-time would also benefit intermittent renewables, distributed flexibility and demand response.

Moving gate closure further out (e.g., 3-4 hours before delivery) would limit the ability of market participants to respond to changes in production forecasts even further. With increasing shares of intermittent renewables and flexible technologies, the need to update forecasts closer to real time will become more important, in order to reflect the latest weather information and asset status and provide more accurate information to minimise required correction actions by the ESO.

[46] Energy Tag (2021) Accelerating the transition
[47] Kocha, Christopher and Phillipp Maskos (2020) Passive balancing through intraday trading : whether interactions between short-term trading and balancing stabilize Germanys electricity system
Kocha, Christopher and Lion Hirth (2019) Short-term electricity trading for system balancing

g) We do not see a convincing case for replacing the current self-dispatch model with central dispatch

As acknowledged in the consultation document, “[A]ny transition to centralised dispatch would likely entail significant implementation costs, challenges and risks for participants. The benefits would therefore need to outweigh these risks, and any potential implementation would need to minimise any market disruption.”

We do not believe that any potential benefits of introducing central dispatch would be worth the uncertainty and disruption it would cause. Recognising that there may be a range of options under the general heading of ‘central dispatch’, we do not think that any further centralisation of the optimisation function beyond the degree of centralisation already embedded in the balancing mechanism and ancillary services is desirable.

We have serious reservations about the efficiency outcomes that can be delivered by a single central algorithm in a system that is a lot more diverse and dynamic than the fossil-fuel based electricity system of the past. The question between central dispatch and self-dispatch is essentially a question of whether a central algorithm or decentralised decision-making by market participants would deliver more efficient dispatch outcomes. The question is impossible to answer as it depends on too many variables and assumptions.

An effective central dispatch system would be exclusively dependent on the efficiency of a single central algorithm, the quality of inputs, its flexibility to accommodate for adjustments as conditions change close to real time, and its ability to evolve in line with a fast-changing resource environment. Central dispatch will not remove the need for the ESO to significantly improve its technical capabilities. It will also not change the reality that in a decarbonised system – and with increasing electrification of demand – the resource base will require a lot more adjustments close to real time to ensure balancing and system stability.

At the same time, we already have relatively well-functioning markets and a self-dispatch system where market participants have developed significant optimisation capabilities and have the best understanding of their own assets and customer base. Minimising distortions to market functioning, enabling the ESO to dispatch resources efficiently and improving its operational capabilities through technology development, streamlining products and developing further constraint markets, improving information sharing and forecasting tools, are all key enablers for a well-functioning self-dispatch system. A decentralised, self-dispatch response is a lot more suitable, in our view, for a dynamic and fast evolving system based on distributed renewables and flexibility assets.

We have commissioned Frontier Economics to consider the potential advantages and disadvantages of introducing central dispatch. The report – to be submitted separately to DESNZ – also contains a section that discusses how to improve the efficiency of dispatch within the existing paradigm.

For the avoidance of doubt, were this proposal to be considered further, it would be essential that a fully quantified and evidenced impact assessment is prepared, given the extensive and material costs we believe would ensue from any intervention of this kind.

h) Literature and international examples on central dispatch

To the extent of our knowledge, there is no international example of a market where a move to central dispatch offers a compelling case for change for the use case in GB. Looking at the academic literature on central dispatch, the evidence of efficiencies is largely based on assumptions of perfect information, algorithm performance and scalability, and sufficient short-term flexibility embedded in the design. The capabilities of the design in the context of a decarbonised system based on distributed renewables and low-carbon flexibility, as well as its scalability to meet the demands of such a system, in our view, remains largely untested.

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

The Government should only intervene in the market where the balance of evidence suggests that market forces alone will not deliver social benefits needed to best protect the interests of current and future consumers. A good example of market failure is CO2 emitters not being exposed to the societal costs of those emissions, hence the need to intervene in the market to disincentivise CO2 emissions. Economists generally agree that the most efficient way to do this is through a carbon price.

In considering the most appropriate reforms under REMA, we strongly urge DESNZ to return to the starting point of only seeking to intervene in the market where there is evidence of clear and demonstrable market failure. For the avoidance of doubt, there is not a market failure where there is an existing market solution to management of a particular risk. For example, there are companies operating in the market today whose business model involves managing price and volume risk on behalf of investors in renewable plant: i.e. PPA offtakers. The Government should not be removing price and/or volume risk from generators and placing them onto consumers where there are existing and potential market participants willing and able to offer that service at competitive prices.

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

Not entirely. A very important interaction that this consultation has missed is between the remaining REMA reform options and the current and potential future reform of the GB retail electricity market, where there is currently a price cap applied to default tariffs for residential customers.

Consistent with our engagement with the REMA and retail teams over the past year, we continue to urge DESNZ to ensure that wholesale electricity market reforms are complementary to – and at least compatible with – the retail electricity market. As we have shown previously for example, it is difficult to justify supporting both a retail price cap and locational wholesale pricing where demand is exposed to the locational price. DESNZ' "Future default tariffs: call for evidence" published in February this year[48] does not mention REMA. Nor does this REMA consultation mention the Future default tariffs: call for evidence. These

[48] DESNZ (2024). Future default tariffs: call for evidence

reform programmes need to be joined up urgently and explicitly. Holistic thinking is needed to deliver an electricity market design that best protects current and future consumers.

LCP Delta's analysis does not properly consider the interactions with the retail market, and entirely omits any discussion of the compatibility between the retail price cap and zonal wholesale pricing. Perhaps LCP does not discuss the retail price cap because it assumes that only electrolyser demand is exposed to the zonal price. However, DESNZ has not ruled out the option that demand is exposed to the zonal price. It is challenging to reconcile the retail price cap and effective retail competition with demand being exposed to a locational wholesale price, as the two reports by Frontier Economics we submitted to DESNZ last year demonstrate. We are formally re-sending those two reports to the REMA team as part of our response to this consultation.

We do not envisage the p/kWh price cap being removed in the medium term. Unless DESNZ disagrees, we recommend that REMA reforms are compatible with the continuation of the p/kWh price cap.

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

Not entirely. The Government's definition of "Legacy Arrangements" is restricted to agreements reached between companies and relevant public bodies via support schemes. Under this definition, the consultation states that Legacy Arrangements in scope would be the Contract for Difference, Capacity Market, Renewables Obligation, Feed-in-Tariffs, Net Zero Hydrogen Fund, Interconnector cap and floor arrangements, and Nuclear CfD and RAB mechanisms.

We question why Legacy Arrangements would not also include commercial decisions made by companies operating in the GB electricity market outside those support schemes such as the decision to enter into a PPA.

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

There are two main strategic risks to consider with regard to Legacy Arrangements:

1. Risks to investor confidence emanating from the Government making changes to the electricity market framework without having full regard to the legitimate expectations of parties who have made investments and/or commercial agreements on the basis of the electricity market framework without such changes.
2. Legal risk.

There are two main options to mitigate those risks:

- Providing sufficient notice/transition period prior to the implementation of the changes.
- "Grandfathering" existing arrangements for commercial decisions made prior to the decision to make any changes.

As DESNZ notes in the consultation, the need to mitigate risks to investor confidence and related legal risks arising from changing electricity market arrangements through sufficient transition periods and/or grandfathering will impact on the cost-benefits case for making such changes in the first place.