

# Review of Electricity Market Arrangements

**Options Assessment** 



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# 1 Why intervene?

## Context

- 1.1 In July 2022, the first Review of Electricity Market Arrangements (REMA) consultation was published. The 2022 consultation sought views from stakeholders on the full range of issues and options for reforming electricity markets. This was followed by an analysis and summary of responses, setting out key themes, published in March 2023.
- 1.2 Since the first consultation was published, and through extensive engagement with stakeholders and receipt of subsequent feedback, policy and analysis has continued to be developed to support the programme in developing options for electricity market reform.
- 1.3 The aim of this Options Assessment is to support the second REMA consultation and provide additional details regarding the analytical frameworks and bespoke analysis produced to support the development of policy, and specifically its contribution to the decision-making process as the programme moves from longlist to shortlist policy options.
- 1.4 The Options Assessment is a standalone document, but the structure of the assessment mirrors that of the consultation and the four challenges. It summarises for each; the counterfactual, rationale for intervention, the options, and both long-list and short-list assessments of the options. It also summarises more in-depth analysis conducted on the short-list options that remain, as well as emerging thinking, key risks, and dependencies with other policy decisions, as per the consultation.

## Background to the electricity system

- 1.5 The GB electricity system is made up of a mixture of generation technologies, principally offshore wind, solar, gas and nuclear. Over the last decade there has been a major increase in the proportion of renewables on the system which now supply around 40% of our electricity<sup>1</sup>. However, the GB market is still reliant on unabated gas generation (around 40% of our electricity supply) to ensure security of supply<sup>2</sup>.
- 1.6 Electricity generation capacity could need to increase two-fold based on its current installed capacity by 2035 to meet expected increases in demand. This increase is driven primarily by the electrification of other sectors such as heat and transport. As the market develops this means that both electricity demand and supply will become more volatile (due to more drivers of demand and the intermittency of renewable generation) increasing the need for complementary technologies that are flexible and readily dispatchable.
- 1.7 Significant amounts of new capacity have been delivered through government support schemes. Recent success in reducing emissions from the power sector has largely been driven by changes introduced as part of the Electricity Market Reform (EMR)

<sup>&</sup>lt;sup>1</sup> BEIS (2022), DUKES, table 5.6.C,

<sup>&</sup>lt;sup>2</sup>BEIS (2022), Energy Trends, table 5.1

package in 2013. EMR accelerated the journey to a renewables-based system through the Contracts for Difference (CfD) scheme. EMR also introduced the Capacity Market (CM) scheme which has succeeded in ensuring electricity security of supply.

1.8 The graphic below illustrates the key features of the electricity system as it moves from being fossil-fuel based to being fully decarbonised.



- 1.9 Ensuring a smooth and lowest-cost transition towards a renewables-based electricity system will rely on addressing the market issues that arise as a result of a rapidly evolving system with an entirely new set of characteristics. A renewables-based electricity system will contribute hugely towards overall societal welfare by contributing towards our efforts to decarbonise the economy, and also by reducing our exposure to volatile fossil fuel markets. Building a future system with a variety of renewable technologies will also contribute to our domestic energy security through diversification of our energy sources.
- 1.10 Continuing to develop our domestic energy supply will also allow for industrial and technological development, in turn driving growth and export potential for businesses and industry and creating jobs for households. As renewables continue to increase their share of the electricity system it will also provide households and business with opportunities to take advantage of more low-cost periods of electricity through the use of smart services and dynamic tariffs, which will in turn help manage demand and system operability.
- 1.11 However, meeting projected future increases in demand whilst continuing to drive down emissions and ensuring the electricity system remains reliable represents a significant challenge. This is made more challenging by the fact that the sector needs to replace aging generation infrastructure. Notably, it is expected that by the end of this decade all but one of the current nuclear fleet will retire, and much of our existing gas generation fleet was built in the 1990s and 2000s. These issues, alongside the

increasing volume of variable renewables, such as wind and solar power, will pose significant future challenges for managing the electricity system including by changing the nature of the security of supply challenge. Our electricity market arrangements need to be updated to manage these challenges, which is the purpose of the REMA Programme.

1.12 In addition to the new generation capacity which will need to be built, significant network development will be required to facilitate the delivery of electricity generated to demand centres. Electricity network infrastructure, both onshore and offshore, is a key component of the electricity system to enable new capacity on the system to deliver electricity to where it is needed. Overcoming the issue of network constraints, as well as ensuring the planning system can enable the scale and pace of deployment required, will therefore also be critical to decarbonising the electricity system.

## Monetary flows in the energy market

- 1.13 The electricity system, itself, is large and full of complicated system dynamics but at its core it is a system of interactions between Government, electricity consumers, energy suppliers and electricity generators through multiple channels.
- 1.14 Proposed REMA interventions could alter both the channels and the order of magnitude of monetary flows between market participants, with a key consideration of these interventions being to ensure that future market design operates in the interest of consumers as well as incentivising investment.
- 1.15 The electricity system is central to the functioning of the economy and the enablement of productive activity for both businesses and consumers. The total value of monetary flows throughout the electricity system is estimated to be c.£45bn<sup>3</sup>.
- 1.16 The diagram below illustrates the order of magnitude of each of these primary channels between key actors in the system, and how institutional frameworks and market participants interact. It seeks to provide a sense of scale of the value of exchanges between different market participants as well as inform considerations around potential reforms and their interactions with the broader market.

<sup>&</sup>lt;sup>3</sup> C. £45bn (to the nearest £5bn) is the total value of energy end use as published in: DUKES 2023

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#### Illustration notes:

Data in this diagram is from data relating to 2021. Further information is available in appendix C.

This map does not consider the money passed from consumers to suppliers for their services.

The volume of blue/red circles presented are proportional to the net money (in £m) transferred by the stakeholder group (sum of the sources less receipts).

Both net recipients and net sources are represented by colour. Red denotes recipients, while blue denotes sources.

The suppliers circle represents the money consumers pay suppliers for onward distribution.

The widths of arrows are proportional to the total money (in £m) transferred by flows represented.

Acronym	Expansion
CfD	Contracts for Difference
СМ	Capacity Market
LCCC/EMR	Low Carbon Contracts Company/Electricity Market Reform
CPS	Carbon Price Support
CCL	Climate Change Levy
VAT	Value Added Tax
RO	Renewables Obligation
FiTs	Feed-in-Tariffs

#### Market issues and the rationale for intervention

- 1.17 As the electricity system decarbonises, the underlying economics and market dynamics will ultimately change. It is important for the assessment to reflect that REMA interventions will be enacted in a market that has already experienced significant intervention from Government including through EMR.
- 1.18 The electricity system of the future is likely to see an increasing volume of renewable generation assets characterised by intermittent supply, high-upfront capital costs and low operational costs. Over time this will result in a flattening of the supply curve and pose significant revenue uncertainty for merchant generators.
- 1.19 The success of the CfD means that there are now a high proportion of generation assets in the pipeline with fixed price contracts that are also intermittent, meaning they have limited price responsiveness and do not have an incentive to respond to price signals as readily in the wholesale market. As a result, the wholesale market (in particular the day-ahead market) is likely to see increased frequency of periods of excess supply and on average low and falling wholesale prices to reflect the greater volume of intermittent renewables. This phenomenon of increasing renewable supply putting downward pressure on wholesale prices is known as price cannibalisation.
- 1.20 There are also emerging issues around system geography, with more assets constrained by location, for example with offshore wind primarily deployed in the North Sea and nuclear assets restricted to specific sites. With increasing amounts of electricity supply required to meet demand, there is increased strain on networks and periods of congestion. This increased congestion results in a greater number of actions needing to be taken by the ESO in the Balancing Mechanism to equalise supply and demand. These increased costs are ultimately passed onto consumers.
- 1.21 REMA is considering how to intervene to evolve the system to ensure that it continues to provide the most economically efficient means of producing and delivering electricity to consumers. There are four main policy questions, aligning with the four challenges, that REMA is looking to address:
  - What is the role of marginal pricing within the electricity market and how best to decouple gas and electricity prices to pass on the benefits of low-cost renewables?
  - How best to drive investment in low-cost renewables in future?
  - How best to replace unabated gas with low carbon flexible technologies, while maintaining security of supply?
  - How best to operate and optimise a renewables-based electricity system to keep costs as low as possible, taking into account location?
- 1.22 As part of the assessment, and to develop the rationale for intervention, proposed REMA interventions were matched to the specific issues that they were intended to address. The figure below shows the identified market issues and provides a high-level assessment of the extent to which policy options address the underlying market failure.

#### Figure 2: REMA market issues analysis

Rationale for Intervention	Market Issue	<b>REMA Policy Option</b>	Extent Option Solves Market Failure	Desired outcome
Distributional impacts – marginal pricing & fossil fue	Market arrangements lack resilience to commodity price shocks resulting in consumer exposure to high electricity prices.	<ol> <li>Reformed CfD options</li> <li>Green Power Pool</li> <li>Split Markets</li> </ol>	<ol> <li>Consumer exposure decreases over time with increasing renewable penetration &amp; limits inframarginal rents as generators pay LCCC back when WM price &gt; strike price</li> <li>Not more than status quo (1)</li> <li>Theoretically could mitigate more than status quo (1) but unclear whether benefit is deliverable.</li> </ol>	Increased resilience to commodity price shocks.
Negative externality - Lack of locational operational signals	Constraint costs are increasing; increasing system costs, which are paid by consumers.	<ol> <li>Zonal pricing</li> <li>Nodal pricing</li> <li>Constraint markets</li> <li>Other constraint management options</li> </ol>	<ul> <li>1) Each zone has their own price reflecting transmission costs and constraints, thereby internalising the externality.</li> <li>2) Marginal costs of supplying electricity is calculated at each node accounting for local supply, demand, transmission constraints &amp; losses.</li> <li>3) Could internalise the externality by creating a separate market for assets providing constraint management. Extent to which depends on policy design.</li> <li>4) Other options being considered but at early stages</li> </ul>	Increased system efficiency and reduced costs as generators take congestion & losses into dispatch decisions.
Negative externality – limited locational investment signals	Constraint costs are increasing; increasing system costs, which are paid by consumers.	<ol> <li>Zonal pricing</li> <li>Nodal pricing</li> <li>Locational CfD</li> <li>Locational CM</li> <li>Reformed Transmission Charging/Access</li> </ol>	<ul> <li>1) Local system conditions signals where to invest additional capacity, storage and transmission infrastructure.</li> <li>2) As above but more granular so sharper signals.</li> <li>3) Adding locational element to CfD auction couldsend an investment signals for assets wishing to obtain CfD.</li> <li>4) As above but for assets wishing to obtain a CM contract.</li> </ul>	Reduced network reinforcement costs and overbuilding capacity, resulting in lower electricity bills as generators consider impact on network of where to locate.
Positive externality/ Imperfect info - Missing money problem; reduced running hours (& WM revenues) and risk averse investors deters investment in firm and flexible assets.	Risk current market arrangements will not deliver enough flexible capacity.	<ol> <li>Cross technology revenue cap &amp; floor</li> <li>Optimised capacity market</li> <li>Centralised reliability option</li> </ol>	<ul> <li>Guarantees minimum revenue for flex assets, addressing impacts of market failures leading to missing money.</li> <li>Addresses 'missing money', incentivises the availability of low carbon and/or low carbon flexible capacity in the Capacity Market.</li> <li>Addresses market failures as centralised body buys reliability options ensuring S=D during peak periods. May provide better DSR investment signals but no reallife evidence.</li> </ul>	Increased investment in flex assets resulting in a more efficient low carbon system, that is easier to operate and meets security of supply.
Key REMA Objective		Market barriers           curity of Supply         Cost-effectiveness		n't address arket failure ? Unsure - early stage of policy design

Rationale for Intervention	Market Issue	<b>REMA Policy Option</b>	Extent Option Solves Market Failure	Desired outcome
Imperfect info - role of unabated gas is unclear post-2035 leading to uncertain investment / retirement case	The system needs to manage the transition away from unabated gas.	<ol> <li>Strategic reserve</li> <li>Targeted tender</li> <li>Optimised capacity market</li> </ol>	<ol> <li>\$ 2) would work alongside options addressing 'missing money problem' for flex assets.</li> <li>1) Ensures existing gas plants are not closed prematurely; extent addresses failure depends on when auctions occur</li> <li>2) Used to tender investment in additional capacity; long term contracts provides more certainty</li> <li>3) Decisions on how to optimise participation of low carbon techs sends market signals on unabated gas' role</li> </ol>	Managed transition away from unabated gas, increasing chances of meeting decarbonisation and security of supply objectives.
of production - Price cannibalisation deters investment in new renewable assets and early retirement risk	Risk current markets will not deliver the required new build renewable capacity & existing assets will retire early once support contract ends.	<ol> <li>Reformed CfD options</li> <li>Green Power Pool</li> <li>Split Markets</li> </ol>	<ul> <li>Address impacts of price cannibalisation by insulating CfD renewable assets from price risk via strike price, other forms of CfD also mitigate price risk but in different ways.</li> <li>Prevents price cannibalisation for renewable assets since pool price = LRMC</li> <li>Prevents price cannibalisation for all assets</li> </ul>	Increased rate of renewable buildout and reduced risk of early retirement, reducing risk of missing decarbonisation targets.
Barriers to entry - No clear route to market for small scale renewables	Risk current markets will not deliver the required new build renewable capacity	<ol> <li>Green Power Pool</li> <li>Split Markets</li> <li>PPAs</li> </ol>	<ul> <li>Could be designed to address barriers to entry</li> <li>Could be designed to address barriers to entry</li> <li>Does not address barriers to entry with CfD but potential to provide alternative route to market</li> </ul>	Increased deployment of renewable assets of all sizes, reducing risk of missing decarbonisation targets.
Imperfect info / high production costs / high transaction costs - Challenges in PPA market limiting its	Risk current markets will not deliver the required new build renewable capacity	Deal with these market failures.	<ul> <li>Too early to tell</li> <li>1) helps the <i>investment</i> case. Won't affect<i>operational</i> signals unless penalty is tied with scarce events.</li> <li>2) Helps co-ordinate optimum dispatch decisions and ensure</li> </ul>	Reduced risk current markets do not deliver required new build renewable capacity needed to meet decarbonisation targets.
role in bringing forward new assets. Positive externality - Sustained response	Risk current market arrangements will not deliver enough capacity with sustained response	<ol> <li>Optimised capacity market</li> <li>Central dispatch</li> <li>Centralised reliability option</li> <li>Cross technology revenue cap and floor</li> <li>Reforming ancillary services</li> </ol>	<ul> <li>storage assets discharge when its optimum for the system.</li> <li>3) Centralised body buys reliability, therefore valuing sustained response and the right discharge behaviour.</li> <li>4) Helps investment case and operational signals as revenue floor could reduce incentive to charge / discharge frequently.</li> </ul>	Increased provision of sustained response assets, minimising costs of and improving operability of the system.
not valued Positive externality - Demand reduction not valued A	capability. Electricity demand is higher than necessary; increasing consumer costs.	<ol> <li>Market arrangement adjustment</li> <li>Pay for performance / auction / supplier obligation</li> </ol>	<ol> <li>Significant complexity in integrating electricity demand reduction into existing markets meaning intervention could have unintended consequences.</li> <li>Possible duplication given existing/indevelopment downstream policies for end-users and ongoing retail market reform.</li> </ol>	Managed increase in electricity demand; reducing consumer costs making security of supply and decarbonisation harder to achieve.
Key REMA Objective		ion failure Market barriers	Completely addresses the market failure	

#### Figure 2: REMA market issues analysis (continued)

Rationale for Intervention	Market Issue	<b>REMA Policy Option</b>	Extent Option Solves Market Failure	Desired outcome
Imperfect info - role of unabated gas is unclear post-2035 leading to uncertain investment / retirement case	The system needs to manage the transition away from unabated gas.	<ol> <li>Strategic reserve</li> <li>Targeted tender</li> <li>Optimised capacity market</li> </ol>	<ul> <li>1) &amp; 2) would work alongside options addressing 'missing money problem' for flex assets.</li> <li>1) Ensures existing gas plants are not closed prematurely; extent addresses failure depends on when auctions occur</li> <li>2) Used to tender investment in additional capacity; long term contracts provides more certainty</li> <li>3) Decisions on how to optimise participation of low carbon techs sends market signals on unabated gas' role</li> </ul>	Managed transition away from unabated gas, increasing chances of meeting decarbonisation and security of supply objectives.
of production - Price cannibalisation deters investment in new renewable assets and early retirement risk	Risk current markets will not deliver the required new build renewable capacity & existing assets will retire early once support contract ends.	<ol> <li>Reformed CfD options</li> <li>Green Power Pool</li> <li>Split Markets</li> </ol>	<ul> <li>Address impacts of price cannibalisation by insulating CfD renewable assets from price risk via strike price, other forms of CfD also mitigate price risk but in different ways.</li> <li>Prevents price cannibalisation for renewable assets since pool price = LRMC</li> <li>Prevents price cannibalisation for all assets</li> </ul>	Increased rate of renewable buildout and reduced risk of early retirement, reducing risk of missing decarbonisation targets.
Barriers to entry - No clear route to market for small scale renewables	Risk current markets will not deliver the required new build renewable capacity	<ol> <li>Green Power Pool</li> <li>Split Markets</li> <li>PPAs</li> </ol>	<ul> <li>Could be designed to address barriers to entry</li> <li>Could be designed to address barriers to entry</li> <li>Does not address barriers to entry with CfD but potential to provide alternative route to market</li> </ul>	Increased deployment of renewable assets of all sizes, reducing risk of missing decarbonisation targets.
Imperfect info / high production costs / high transaction costs - Challenges in PPA	Risk current markets will not deliver the required new build renewable capacity	Deal with these market failures.	<ul> <li>Too early to tell</li> <li>1) helps the <i>investment</i> case. Won't affect <i>operational</i> signals unless penalty is tied with scarce events.</li> <li>2) Helps co-ordinate optimum dispatch decisions and ensure</li> </ul>	Reduced risk current markets do not deliver required new build renewable capacity needed to meet decarbonisation targets.
market limiting its role in bringing forward new assets. Positive externality - Sustained response	Risk current market arrangements will not deliver enough capacity with sustained response	<ol> <li>Optimised capacity market</li> <li>Central dispatch</li> <li>Centralised reliability option</li> <li>Cross technology revenue cap and floor</li> <li>Reforming ancillary services</li> </ol>	<ul> <li>a) response of elements optimum displater designed to elements of the system.</li> <li>b) Centralised body buys reliability, therefore valuing sustained response and the right discharge behaviour.</li> <li>c) Helps investment case and operational signals as revenue floor could reduce incentive to charge / discharge frequently.</li> </ul>	Increased provision of sustained response assets, minimising costs of and improving operability of the system.
not valued A	capability. Electricity demand is higher than necessary; increasing consumer costs.	<ol> <li>Market arrangement adjustment</li> <li>Pay for performance / auction / supplier obligation</li> </ol>	<ol> <li>Significant complexity in integrating electricity demand reduction into existing markets meaning intervention could have unintended consequences.</li> <li>Possible duplication given existing/in-development downstream policies for end-users and ongoing retail market reform.</li> </ol>	Managed increase in electricity demand; reducing consumer costs, making security of supply and decarbonisation harder to achieve.
Key REMA Objective		tion failure Market barriers	Completely addresses the market failure	

#### Figure 2: REMA market issues analysis (continued)

1.23 Our conclusion is therefore that despite the extent to which intervention has already taken place in the electricity market, there are issues that persist and objectives that will not be delivered without continued, or further, intervention or regulation of the market by government.

## The REMA counterfactual

#### Approach to the counterfactual

- 1.24 The HMT Green Book states that the counterfactual is 'the continuation of current arrangements, as if the proposal under construction were not to be implemented, even if such a course of action is completely unacceptable' and is a core part of the appraisal process. It also states that any counterfactual should not assume away costs of action to maintain the status quo or assume action to meet ambitions within the scope of REMA. This guidance therefore steers us toward a counterfactual which can be inconsistent with achieving net zero and/or create risks around security of supply and/or result in inefficiency such that system costs are high.
- 1.25 The development of a counterfactual is distinct in its application to the electricity market as there is no clear and obvious state of the world that would preside in "the absence of REMA", however it would likely involve trade-offs and compromises to our objectives.
- 1.26 A common theme that runs through any thought experiment to consider what would happen if market reform did not take place is the impact of diminishing investor confidence and lack of clarity over the shape and nature of markets as we prepare for a fully decarbonised electricity system.
- 1.27 This can be mapped to our objectives as follows:
  - Decarbonisation: if market reform does not occur and the future of the investment vehicle and/or policy intervention to deploy intermittent renewables is not reconsidered the distortions which already exist in the current CfD would continue to be exacerbated as a growing proportion of our generation capacity would be on a CfD (as currently designed). In addition, we are not yet seeing the deployment of low carbon flexible technologies at the scale needed to replace unabated gas generation and so reduce overall power sector emissions. Without further clarity, investors are likely to become increasingly hesitant to invest at large scale in the UK, as they need confidence that there will be market arrangements in place to maintain a well-functioning dispatch process and investment climate.
  - Security of supply: investors need clarity in the scale and scope of the need for flexible assets, both low carbon and fossil fuel based. Without signals and commitments to develop market frameworks there is likely to be underinvestment in both low carbon flexible assets and in unabated gas generation. At extremis this could result in security of supply measures such as demand rationing being needed – more likely is that suboptimal and high-cost options would need to be exercised which would also hinder decarbonisation progress.
  - Value for money: the points above, allied to the continuation of the supply and demand mismatch in time and space without intervention or reconsideration of

existing interventions to address it will likely result in higher costs to consumers through the system operator having to pursue costly remedies through balancing and system services.

#### Counterfactual schematic

1.28 Without REMA intervention, electricity market arrangements are unlikely to deliver against our objectives. The insights from our case for change, analysis of market issues, and the subsequent illustration of the counterfactual analysis conclude that in order to ensure the electricity market is able to decarbonise, ensure security of supply, and operate in the interests of consumers it is necessary for government to intervene. The below figure set out logic maps, and end-state impacts, in the event of the CfD, Capacity Market and wholesale market continuing under business-as-usual arrangements, concluding in what we consider to be adverse impacts if there is no intervention to address market issues. Figure 3 (below) sets out what we consider to be the likely adverse impacts if market arrangements remain unchanged.



#### Figure 3: Counterfactual schematics for the CfD, Capacity Market and wholesale market

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- 1.29 Our assessment is that in a no intervention scenario, power sector decarbonisation by 2035 would likely be at risk. Failing to address the distortions caused by current arrangements for investment in new low carbon capacity would likely become unsustainable, requiring ever more costly and aggressive actions to ensure the system can be operated reliably and increasing overall system costs for consumers. In addition, we would be likely to see insufficient investment in buildout of low carbon, flexible assets necessary to achieve decarbonisation (see also causal chain below on security of supply). Overall, this would be likely to decrease investor confidence in market arrangements and increase risk premia, driving up assets' capital and financing costs, as investors hedge against future risks.
- 1.30 There could also potentially be security of supply risks, due to the uncertainty that investors in existing and potential new unabated gas generation would face regarding future decarbonisation pathways and the implications for the expected lifetime of and revenues from their assets. Achieving security of supply at the lowest possible carbon intensity would also be at risk, primarily due to a lack of incentives for and deployment of low carbon, flexible assets. The existing CM does not value these technologies

appropriately or value a sufficiently diverse range of asset characteristics in its design. These technologies would therefore be less likely to be successful at auction and procured through the CM, so would not be deployed at a necessary rate to achieve decarbonisation by 2035. These factors would also increase CM policy costs for consumers.

- 1.31 Additionally, wider market arrangements would provide limited incentives and arbitrage opportunities for short-duration flexible technologies due to low temporal granularity for example.
- 1.32 Without intervention, we would also expect to see increased whole system costs, including balancing costs. For example, if current TNUoS arrangements continued (with no reform), these would not provide sufficient locational investment or operational signals. There would be limited incentives for responsive siting or operational decisions, leading to dispatch inefficiencies, additional network build needs and higher BM volumes, driving increased costs.
- 1.33 In addition, the factors set out above would also increase costs for consumers by exacerbating the distortions present in our current market arrangements, worsening risks to our security of supply, and increasing the likelihood that additional (and potentially more expensive) actions would be needed later both to ensure progress towards a net zero power sector and to maintain a secure and reliable electricity supply.
- 1.34 CfD assets would continue to be insulated from most wholesale market signals; the operational behaviour of these assets would therefore be less likely to reflect the balance of supply and demand and also contribute to these higher balancing costs.

#### Orders of magnitude for the counterfactual

- 1.35 Often power sector modelling relies on the premise that economic agents are able to act rationally and efficiently according to their objectives and "preference functions". This also embeds an assumption of the role of markets and any government intervention operating as intended and crucially without lots of inefficiencies. As the nature of the REMA programme is transformational, it considers multiple interventions at the same time. However, using conventional modelling tools in isolation, often geared towards 'marginal analysis', presents challenges and reliance on these tools would ultimately result in incomplete analysis.
- 1.36 Despite the inherent difficulty and uncertainty in demonstrating the orders of magnitude of the impacts of reform, the Department's Dynamic Dispatch Model (DDM) has been used to produce a stylised, illustrative counterfactual scenario based on our current market arrangements. Further details are set out in Appendix C.
- 1.37 The analysis concludes that, without market reform, system costs over the period 2030-2050 could be around £35bn higher (2023 prices) with carbon emissions that exceed our CB6 and Net Zero commitments. Around half of these additional costs stem from capacity building in suboptimal locations, and the remainder from having to build unabated gas in order to meet the demand for flexible supply in the absence of low carbon flexible technologies. The counterfactual system is assumed to have sub-

optimal locational deployment of capacity relative to demand and reduced deployment of flexible assets relative to net zero compliant scenarios<sup>4</sup>.

- 1.38 There are considerable uncertainties in this analysis. In particular, interconnectors are assumed to be able to play a full role in balancing locational constraints in the counterfactual, which is not currently the case, and it is not clear whether it will be possible in the future. If interconnectors were unable to reduce constraints this function would need to be served by other more expensive assets which would increase the costs in the counterfactual. This is a conservative assumption and therefore, could be a significant underestimate of the potential benefits from REMA. The modelled counterfactual scenario also assumes intermittent renewable deployment is unchanged, which is again a conservative assumption, because current market arrangements may lead to lower levels of investment in renewables than is needed for a decarbonised system.
- 1.39 The analysis assumes that security of supply can be met under the counterfactual. If security of supply was not achieved due to greater investment risk leading to insufficient flexible (and intermittent renewable) capacity being deployed, in turn resulting in more frequent stress events and potentially unserved energy, the economic cost in the counterfactual, and therefore our estimate of system benefits from REMA, would be far greater.
- 1.40 These results are highly stylised, do not reflect government policy, and are only intended to offer an order of magnitude of 'doing nothing' to reform markets in order to cater for a low carbon system. As part of the next stage of the REMA programme, we will develop the modelling tools, parameters, and associated policy choices to provide a more robust estimate of the potential impacts of preferred REMA policy options on the system and consumers.

<sup>&</sup>lt;sup>4</sup> Annex O of the Energy and Emissions Projections (EEP 2021)

# 2 Effective market design and the analytical framework

- 2.1 This section provides an overview of the cross-cutting themes and considerations that are central to the REMA analytical framework and decision-making process.
- 2.2 First, it sets out the vision for what good electricity market design looks like in practice before going into more detail to explain the analytical framework that informs the assessment of the options. Secondly, this section provides an overview of a number of cross-cutting themes and issues that are considered as part of the analysis as well as plans for further work.

## What is good electricity market design?

- 2.3 Markets are at the heart of the GB electricity system. They drive competition and innovation to benefit consumers and provide price signals which guide decisions on electricity supply and demand, investment in new generating capacity and flexibility, and the efficient operation of the system.
- 2.4 A market economy, in economic terms, implies that resource allocation is determined by supply and demand for a particular good. There are number of benefits associated with markets for goods and services, for example:
- 2.5 Markets encourage competition between suppliers. This leads to innovations in products and services as firms are incentivised to improve the efficiency of their processes and quality of their services in order to gain a competitive advantage.
- 2.6 Markets are typically more efficient in their ability to allocate resources because they rely on the determination of a price to signal to the market what goods and services are produced, and how. With prices determined by supply and demand, resources will be allocated to where they are most valued.
- 2.7 The delivery of a low cost, secure and decarbonised power system will therefore require an approach that draws upon the strengths of both market mechanisms and government intervention. These distinct approaches should be regarded as complementing one another, each capable of reaching places that the other cannot. Ultimately, the balance between those two broad sets of levers is dynamic (the appropriate balance will change as the power system and policy objectives evolve) and their interface is nuanced (some interventions draw upon elements of both a market and planned approach).
- 2.8 The theoretical benefits of a market-led approach in achieving our power system objectives can be considered in terms of the different types of efficiency:
  - Allocative efficiency market pricing ensures that assets are allocated to their most valued uses, guiding investment and operation towards technologies, locations and practices that are most economically efficient.
  - Productive efficiency actors within the power system are incentivised to minimise costs and drive internal efficiency in order to remain competitive. Although couched

in terms of production, these competitive pressures apply to suppliers as well as generators.

- Dynamic efficiency market mechanisms incentivise innovation and technological progress, which underpins the continuous improvement of technologies and discovery of more efficient business models.
- 2.9 If market arrangements are designed optimally and are working well, decisions about what, where and how much to build (i.e. investment decisions), and what should be turned on and off at which times (i.e. operational decisions), should be primarily driven by the interactions of generators, suppliers and consumers responding to price signals in the market. This should lead to gains in the types of efficiencies outlined above.
- 2.10 It is recognised that market participants have the best information about their own assets, consumer base, and business models, and that therefore where possible the desire is for investment and operational decisions to be driven by participants. In some cases, these principles must be balanced against other factors, and the existence of the market failures set out previously often mean that markets alone may not deliver our objectives.
- 2.11 The main role of electricity markets should be achieving efficient investment decisions and efficient dispatch decisions. Other government objectives such as industrial policy and redistributive policy are likely to interact with electricity markets.
- 2.12 Getting GB electricity market arrangements right is critical to helping deliver the energy transition and net zero and should provide the right conditions to incentivise investment in the power sector but also harness the benefits of "the market". This can be achieved by:
- 2.13 Encouraging competition between generation technologies to lower the cost of producing electricity, and the system as a whole.
- 2.14 Lowering barriers to entry for new market entrants, in turn, creating the right environment for competition and space for innovative, novel technologies.
- 2.15 Minimising distortions and externalities by ensuring that economic costs are reflected and captured in the system, and adherence to the Polluter-Pays principle to assign the cost of carbon intensive generation technologies.
- 2.16 Ensuring there is enough liquidity in forward markets to enable market participants to effectively manage financial risks, such as unexpected changes in wholesale prices due to system needs or otherwise, through hedging.
- 2.17 As the energy transition progresses, policy mechanisms will need to evolve to ensure that not only is the market able to deliver the right quantity, and scale, of low carbon generation required but also that assets are better able to operate in a way that benefits the system as a whole.

## The Analytical Framework

2.18 This section sets out the overarching analytical framework that has been devised for the assessment of REMA programme interventions, at both longlist and shortlist

assessment stages. It sets out the objectives and explains the approach to ensuring proportionality, the key uncertainties within the REMA environment and how these uncertainties have been considered as part of the development of the analytical approach.

2.19 The original case for change has also been developed since the 2022 consultation. This is described alongside the rationale for intervention in the options assessment under each individual challenge.

## REMA objectives and assessment criteria

- 2.20 The REMA programme's objectives are as follows:
  - Ensure a cost-effective transition as we move to our future net zero consistent power sector,
  - Maintain a secure electricity supply throughout the 2020s and beyond, as we continue to move away from fossil fuel-based generation technologies, and
  - Ensure our decarbonisation ambitions are delivered, so that the power sector contributes towards our legally binding carbon budgets, and we achieve our aim of a fully decarbonised power sector by 2035, subject to security of supply.
- 2.21 We have used these overarching REMA policy objectives, and the REMA Assessment Criteria set out below, to evaluate the different policy options under consideration:

Criteria	Explanation
Best value for money	Market design should lead to solutions that minimise overall system costs for consumers and sub-groups of consumers, with ongoing incentives to keep costs as low as possible and drive innovation (through competition where appropriate). Markets should be open to all relevant participants, including demand-side and innovative technologies.
Deliverability	Changes to market design should be achievable within designated timeframes and seek to minimise disruption during the transition, taking account of the highly complex and integrated nature of the power system.
Investor confidence	Market design must drive the significant investment in low carbon technologies needed to deliver our objectives. Risks will differ by technology type but should be borne by those market participants that are best able to manage it.
Whole-system flexibility	Market design should incentivise market participants of all sizes (both supply and demand side) to act flexibly where it is efficient to do so. It should also promote greater coordination across traditional energy system boundaries including between electricity and other vectors like heat and hydrogen, to enable effective optimisation across the whole system.
Adaptability	Market design should be adaptive, responsive to change and resilient to exogenous shocks. It should help ensure delivery of our objectives in a wide range of scenarios and should be robust to

#### Table 1 – REMA Assessment Criteria

uncertainty, for instance regarding commodity prices and
technology costs.

2.22 The objectives and the criteria provide the basis for the assessment and the framework for determining which options should proceed beyond the long-list assessment stage. The assessment also considers in detail the rationale for intervention, and associated market failure, that apply to each of the challenges.



#### Overarching assessment

- 2.23 The appraisal of REMA reforms has considered the systemic nature of the programme and is different from a typical cost-benefit analysis because:
  - REMA reforms involve fundamental structural change in the electricity market. The changes would be enduring because investment decisions create path dependency and the interventions act on tipping points (where small interventions, for example repositioning assets within the merit order, fundamentally change the deployment mix) and leverage points (in which interventions act on key nodes in the system).
  - The proposed reforms pull multiple different levers which interact with each other directly; the highly interconnected system of electricity markets implies there are also material indirect implications (through prices and quantities); and given the long run nature of the reform (enabling net zero) there is substantial uncertainty.
  - The extent of the policy, and the breadth of the approach to the evaluation of REMA has meant that it has been classified as a 'transformational' project in Green Book terms. This means in practice that analysis of the programme has started at a very strategic level, in which we have undertaken substantial analysis of the case for change and how each element of this interacts to refine our rationale for intervention.
- 2.24 Following this, the approach has evolved to employ i) best practice systems analysis, including a system mapping approach to determine the interactions between policy options and the rest of the electricity system; and ii) logic mapping to articulate the benefits cases for individual options.

- 2.25 The assessment, as mentioned previously, also drew on traditional market failure analysis to step between our vision of the electricity system and how market interventions might lead to more efficient outcomes. By doing so, a potentially very large option space can be reduced considerably.
- 2.26 Given the scale of reform, the breadth of the policy options and their implications for the electricity market, we also recognise the potential for unintended consequences that arise as a result of intervention, defined as a situation where government intervention in the electricity system would fail to achieve its intended objectives and possibly result in unintended negative consequences. This is often referred to as "government failure" and is an economic inefficiency resulting from intervention. We have considered this as part of our assessment of "deliverability" as part of the REMA Assessment Criteria.

#### Framework to enable move from long-list to short-list options

- 2.27 The assessment of the options was then divided into two phases. First, to support a longlisting assessment of options considered in the 2022 REMA consultation, five REMA assessment criteria were identified for REMA policies as set out in the previous section. These criteria are set out in Table 1.
- 2.28 Each option was assessed on the basis of these criteria and where options failed one of the assessment criteria, they were eliminated. The options assessments for each challenge summarise the economic assessment undertaken for each option considered in the longlist and the underpinning rationale for why a given option was not progressed to the shortlist assessment. A range of stakeholder evidence also underpinned assessment against the criteria; this is set out further in Appendix D.

#### Framework for short-list assessment

- 2.29 As part of the shortlist assessment of options that remain under consideration in the next phase of the REMA programme, in-depth analysis of all options which did not fail any of the assessment criteria has been conducted. This assessment (as set out in this document) seeks to provide the relevant details of the analysis, highlighting key risks, evidence gaps and dependencies.
- 2.30 This shortlist assessment first clarifies the theory of change by developing our analysis of existing market issues before developing this into a market failure assessment to trace through the precise areas of existing markets where REMA option designs could help resolve issues, and how these would respond to our proposed interventions.
- 2.31 For the majority of options<sup>5</sup>, the analysis includes a structured logic mapping assessment which identified the logical sequence of how inputs (e.g. policy changes) lead to desired outputs and outcomes what would have to be true for our policy to have its desired effects, and what direct dependencies will have a bearing on that.
- 2.32 The assessment then sets out the evidence base to appraise the option's performance against its rationale. The evidence mix and approach differs by option given the wide range of reform types considered, and the depth of analysis required to inform decisions on each option. In totality, the assessment draws on research project

<sup>&</sup>lt;sup>5</sup> We did not logic map options for demand reduction given its wide systemic interactions we considered the system map a sufficient tool for these purposes. We also did not map operability options, given that the mechanisms through which impacts exist are more diffuse.

findings, illustrative modelling, stakeholder feedback, systems dynamics analysis, and economic theory (e.g. the extent to which the option is expected to react to market signals).

- 2.33 Each section also includes an assessment of the dependencies on decisions regarding options described elsewhere, for which we use a strategic level complementarity assessment and systemic evidence gathered through system mapping. The assessment also identifies remaining unknowns, areas where evidence is incomplete or requires further development, and further work.
- 2.34 The OA does not provide a quantified Net Present Value (NPV) for options in this assessment. Given the wide options space, substantial interdependencies and modelling limitations, a single NPV range would have been wide, with relationships that matter to stakeholders unaddressed, and highly abstracted from the actual reforms. For the next stage of the programme the assessment will allow a fuller quantification of the impacts.

#### Future considerations for REMA – a system-wide approach

- 2.35 In the next phase of REMA, interactions between policy options will need to be developed and understood in greater level of detail in order to discern key trade-offs and inform decisions on holistic market design options and choices.
- 2.36 The approach in this options assessment has been to consider options in isolation. Options have generally been appraised against a counterfactual of business-as-usual market design. Both the system map approach and logic maps have helped us identify the key dependencies and likely impacts of the options on the wider system, but we have not undertaken a detailed assessment of how different REMA options would work together.
- 2.37 Electricity market reform is a whole-system problem, and so requires whole-system analysis in order to determine the optimal market design. Focusing on any one single part of the system without consideration of how it interacts with other parts is likely to lead to sub-optimal outcomes. 'Whole systems approaches' involve identifying the various components of a system and assessing the nature of the links and relationships between each of them. We need to consider how the remaining options across these challenges interact with each other, and with the wider energy system.
- 2.38 Chapter 7 in the accompanying consultation document provides our initial assessment of options compatibility. We conclude that there is a high degree of compatibility between the remaining options, meaning choices in one area do not go very far in defining overall packages of reform. However, we also identified there are complex and impactful interactions between our options. For example, locational wholesale pricing would be a significant change to the underlying market on which support schemes are designed around.
- 2.39 There are also complex interactions with existing contractual arrangements, categorised as 'legacy contracts' in Chapter 6 of the consultation. The implementation of REMA options may change the risks faced by existing assets. We will need to consider the case for protected existing assets from these changes, including how protection changes the benefit case for REMA options.

2.40 In the next phase of the REMA Programme, we will deepen our analysis of options compatibility as well as how combinations of policy options work best together, will be developed. This will include further policy development on the design choices that determine the interactions between options. It will also include a more detailed assessment of the impact of legacy contract protection.

## 3 Options and assessment

### Introduction to options assessment

- 3.1 The assessment is divided into four primary sections, one section for each challenge. Each section begins by setting out the relevant challenge-specific context and key market failures driving this challenge, the counterfactual and dependencies for each proposed reform before outlining the long-list and short-list assessments for each option.
- 3.2 The discussion on the REMA policy options is split between those dismissed in the longlisting stage, and those for which we have conducted a more detailed, shortlist assessment. That is to say, the longlisting stage applied an initial filter of the options to identify whether any failed the REMA assessment criteria outlined in the previous section. Where the initial assessment showed that an option failed one of the criteria, only a short form discussion is provided in this document. The shortlisting stage then devotes greater detail to assessing the options that passed all assessment criteria.

## Options under consideration

3.3 Figure 4 sets out our updated assessment of options and illustrates how the options are grouped under each challenge area. Options that were discounted in the previous consultation response have been excluded as these options are no longer being considered. The option space includes all options we are taking forward into the next phase of REMA.

#### Figure 4: REMA Options Space

Challenge 1: Passing through the value of a renewables-based system to consumers					
Wholesale market features	Unified, Pay-as- clear wholesale market				
Challenge 2: Investing to create	renewables-base	d system, at pace			
Mass Low Carbon	Existing CfD	Deemed CfD	Capacity-based CfD	Reference price reform	Partial CfD
Challenge 3: Transitioning away system	from an unabated	l gas-based systen	n to a flexible, resili	ent, decarbonised	electricity
Capacity Adequacy	Bespoke support	Optimised CM (Reforms to the CM to maintain security of			
Flexibility	technologies	supply and enable a transition to low carbon)	Distributed low carbon flexibility review		
Challenge 4: Operating and opti	mising a renewab	les-based system,	cost-effectively		
Wholesale Market - Location	National Pricing	Zonal Pricing			
Wholesale Market – Balancing	BM Reforms				
Wholesale Market - Dispatch	Self-Dispatch	Central Dispatch			
Wholesale Market – Settlement Period	Current Period (30 mins)	Shorter Period			
Wholesale Market – Gate Closure	Current Period (1 hour)				
Alternatives to Locational pricing	Network Charging	Network Access	Expanding measures for constraint management	Optimising the use of cross-border interconnectors	Locational CfD*
Operability	Range of measures to be taken forward with NESO				
Кеу					
Current arrangements continue REMA options – under consideration * Not fully discounted, but not being considered as a stand-alone option Pogressed outside					

## Assessment of challenge 1 options

#### Overview and context

3.4 Challenge 1 is concerned with the role of marginal pricing in electricity markets, and how best to decouple gas and electricity prices to pass through the benefits of low-cost renewables to consumers. In the current system, the wholesale price is set with respect to the cost of the marginal asset and most assets receive this price even though their own marginal costs will be lower. This is a prominent issue as gas power stations are typically the marginal assets on the system, therefore recent high gas prices faced by gas generators have played a significant role in setting the wholesale electricity price at a time of very high marginal costs, leading to concern about high inframarginal rents for some generators.

3.5 The options primarily related to this challenge are listed below. This section proceeds by outlining how this challenge relates to the counterfactual described in the previous section, and how it responds to the scenarios set out above. The market failures involved in this challenge are also outlined before setting out the detail of the longlisting and shortlisting assessment of each option as to their effectiveness and proportionality in addressing the market failures.

#### Table 2 – Challenge 1 options

#	Option name	Assessment style
1	Wholesale market based on marginal pricing (alongside a CfD-type mechanism for renewable generation as detailed in counterfactual)	Shortlist
2	Possible design of alternative wholesale models (split market and Green Power Pool)	Longlist: split market failed all assessment criteria, GPP failed Deliverability and Investor Confidence assessment criteria
3	Demand reduction: Strengthening existing departmental energy efficiency policies	Shortlist
4	Demand reduction: Existing Markets - Capacity Market	Longlist: failed Value for Money assessment criteria
5	Demand reduction: Bespoke Intervention - Pay for Performance Scheme and Auctions	Longlist: failed Value for Money assessment criteria
6	Demand reduction: Pan REMA options, e.g., Supplier/Distributor Obligation	Longlist: failed Value for Money assessment criteria

3.6 In the consultation, under this challenge, potential barriers are highlighted that may limit growth in the Power Purchase Agreement (PPA) market. As explored in the consultation, it is not clear at this stage whether government intervention or action in this market would aid or hinder growth, and so the programme is still seeking to gather evidence on the state of the PPA market and its growth potential. These options have therefore been excluded from the options assessment.

#### Counterfactual and dependencies

- 3.7 Current business as usual for this challenge sees marginal pricing based on short-run marginal costs for all technologies remain the way in which value is passed to consumers through wholesale markets. As such, the cost of the marginal generator will still set wholesale prices in the forward and spot markets, although the way in which these prices are passed through overall is affected by current arrangements including market interventions.
- 3.8 Over time it is expected that CfDs will decouple wholesale prices from gas. This is because generators receive lower, or potentially negative, difference payments.
- 3.9 Whole system modelling underpinning the counterfactual analysis shows that the prevalence of periods in which fuel costs directly influence wholesale prices will fall, even without intervention. This assumed that around 70% of generation will be covered by CfD (or regulated asset base for nuclear generators) in 2035, compared to around

10% today, and that around 5% of demand is reduced through end use sector energy efficiency policy, broadly in line with the government's carbon budget delivery plan.

3.10 Departmental electrification and energy efficiency policy also represents a key dependency in delivering the above change. Noting this dependency, our assessment has regard to the departmental high and low demand scenarios as well as a further sensitivity analysis discussed below. Furthermore, CfD reform, which represents another key dependency, is discussed in more detail under challenge 2.

#### Rationale for intervention

- 3.11 As set out in the consultation document, there are a number of features which could distort market outcomes. Table 3 identifies several market failures relating to marginal pricing which drive the issues described in this challenge. Consideration was given to whether there was anything fundamental about the wholesale price being driven by marginal price that might constitute a market failure. Whilst the scale of commodity shocks and the existence of a single wholesale price across technologies raises the prominence of the issue in electricity, this does not constitute a market failure in and of itself.
- 3.12 Table 3 matches market failures and issues to the options which address them. Given the interrelatedness of electricity market issues, some are discussed under other challenges.

#	Candidate market issue	Market failure in GB electricity markets	Intervention area
1	Current market arrangements lack resilience to commodity price shocks. This has resulted in consumers being exposed to high electricity prices and not benefitting from cheap renewables.	This is not a market failure, but government could choose to intervene based on clear distributional impacts.	GPP, Split market, CfD reforms (chapter 2)
2	There is a risk that current market arrangements will not deliver the required new build renewable capacity to meet our decarbonisation targets.	Inability to fully recover fixed costs through energy markets leads to 'missing money', deterring investment in new renewable assets thereby allowing climate change negative externalities to persist as decarbonisation of the power sector slows. Near-zero marginal cost of production: as the penetration of renewables increases, cost structures will lead to wholesale electricity prices falling to close to zero more frequently during periods of low demand / high renewable output. This is termed 'price cannibalisation'. In addition, increased frequency of negative wholesale prices could create additional uncertainty over expected revenue that could increase costs of deployment and/or reduce the pool of available capital creating risks around renewable deployment.	GPP, Split market, CfD reforms (chapter 2)

#### Table 3 – Challenge 1 market issues

#	Candidate market issue	Market failure in GB electricity markets	Intervention area
3	Insufficient deployment of demand reduction technology (particularly energy efficiency) which leads to undesirably high prevalence of periods where high marginal cost assets set prices.	Several features of electricity markets may distort the competitiveness of energy efficiency technology vis-à-vis generation technology. These include disaggregated revenue streams; barriers to adoption; and shielding consumers from locational and temporal signals.	Demand reduction interventions

#### Options

#### Long-list assessment

Possible design of alternative wholesale models (split market and Green Power Pool)

- 3.13 The longlisting assessment dismissed options where it was identified that the underlying rationale for intervention was insufficiently strong or, relatedly, where all the responses except business as usual failed the assessment criteria, such that business as usual was preferable.
- 3.14 In the case of challenge 1, the assessment dismissed options targeting the marginal pricing mechanism specifically the Green Power Pool and Split Market. These proposals have been discounted based on their performance against the assessment criteria. The split market failed against all factors and the green power pool failed against investor confidence and deliverability. Whilst the consultation document provides a substantive discussion on the rationale to discount, this section will provide a short assessment focussed on the relevant market failures detailed in the above table 3 which relate to the wholesale market.

Design features of transformative options	Green Power Pool (GPP)	Split Market
Both create a separate market for renewables, with prices set at long- run marginal costs (LRMC), so incorporating capital costs.	GPP is an optional pool for renewable electricity existing alongside the wholesale market. GPP is based on relatively long- term contracting.	Separate renewable market is one section of a split wholesale market. Power is purchased in this market both over long-term timescales and closer to real- time.
Both options are relatively transformational, with the split market involving a greater degree of change.	GPP operates alongside an (otherwise relatively unchanged) wholesale market, and excess power from the GPP would be 'spilled' into the wholesale market at short-run marginal cost.	Two separate markets created for different types of generation, which dispatch separately with no direct interaction.

#### Table 4 – Key design features of Split Market and Green Power Pool proposals

Design features of transformative options	Green Power Pool (GPP)	Split Market
Both involve continuation of a short- run marginal cost market structure for dispatchable assets, such as gas-fired power stations and batteries.	Dispatchable assets participate in an existing wholesale market (alongside some renewables that may not participate in the GPP).	Dispatchable assets participate in one section of a split wholesale market, in which renewables cannot participate.
Varying levels of voluntary / compulsory participation between the options	Participation in the GPP would be voluntary in the same way that participation in today's CfD is voluntary, so some renewables may not participate in the GPP.	Compulsory participation for relevant assets in the relevant sections of the market – so all renewables participate in one section of the market, and all dispatchable assets in the other.

- 3.15 The split market is an untested, transformational option and would likely increase system costs without addressing market issue 1 in table 3, i.e. delivering price decoupling (as the price differential between the two markets would likely be traded away). Prices in the LRMC market would also need to be set in advance (potentially through a CfD-style mechanism) but this would be challenging to design effectively in practice and create significant regulatory uncertainty throughout the transition period. There are also a number of consumer protection issues inherent in exposing end users to tariffs that differentiate between the two markets (and therefore reward those who are able to shift demand). DESNZ has not identified a viable model that resolves these issues.
- 3.16 As part of the assessment of the green power pool, we conducted a journey mapping exercise to understand its potential viability in practice and the hypothetical experience of different market participants (Figure 5).
- 3.17 The journey map considers potential behaviour across three system states, or scenarios: where renewable supply in the pool does not meet contracted demand and there is renewable scarcity overall (scenario one); where there is an excess of renewable supply in the pool and scarcity in the wholesale market (scenario two) and where there is excess renewable supply overall (scenario three).

### Figure 5: Green Power Pool – Journey Map

Journe	y Mapping tl	pping the Green Power Pool (GPP) SCENARIO 1: Renewable Scarcity in Por			SCENARIO 2: Excess Renews scarcity in Wholesale Mai	ables in pool. Ket	SCENARIO 3: Excess Renewables overall	
Stakeholder	Auction (Supply Side)	Allocation (Demand Side)	Forwards markets (Pre- forecast)	Forwards Markets (Post- Forecast)	Day Ahead (DAH)	Intraday	Gate closure	Imbalance Settlement
Pool Operator	Sets auction parameters and timelines. Administers yearly auction.	Runs allocation. Sets GPP price based on auction results.	Gathers data from GPP generators to make forecast. Takes actions to improve ability to match demand.	Provides information to suppliers on expected pool volumes.	Takes Expected volume bids from GPP generators.	Sells excess generation into Wholesale Market at SRMC. If scarce, suppliers supply DSF/buy from WM.	Sells any remaining excess into the Balancing Market (BM)	Pool operator is responsible for any imbalances caused by GPP generators
Ineligible Generation	No action	No action	1. Sells a portion of generation ahead (via bilateral /over the counter (OTCs) trades)	1. Sells a portion of generation ahead via bilateral trades OTCs etc. Higher demand for these foward trades - but gen may prefer to sell at DAH/ID	1. Sells unhedged generation into DAH market	Continues to refine positon.	Submits bids/offers in the BM to turn up or down dependent on system need	No change from status quo
			2. Sells a portion of generation ahead (via bilateral/OTCs)	2. Sells a portion of generation ahead via bilateral trades OTCs etc.	2. Sells unhedged generation into DAH market			
			3. As above. Risk averse generators may concentrate hedging pre-forecast	3. Sells a portion of generation ahead via bilateral trades OTCs etc.	3. No action for gas. WM clears at a lower price than GPP - BECCS/ Nuclear treated as must-take			
	No action	Contracts distributed to suppliers	Suppliers trade contracts amongst themselves, and with financial intermediaries. Suppliers hedge volume risk by buying forwards/futures/option contracts in wholesale market, including DSR. Offer consumers tariffs which trade off price and firmness.	1. Suppliers contract to cover shortfall by procuring supply-side flex or demand turn down.	1. Suppliers contract to cover shortfall by procuring supply- side flex or demand turn down	Suppliers buy or sell in intraday markets to ensure final VM position complements actual GPP supply	Not Applicable	
Suppliers				2. Suppliers unwind their unneeded WM positions.	2. Suppliers unwind their unneeded VM positions			
				3. Suppliers unwind their unneeded WM positions.	3. Suppliers unwind their unneeded VM positions.			
Suppliers (Volume Risk Caveat)	No action di	Contracts	As above, but some suppliers have a higher volume risk appetite (those with more	1. Suppliers start to cover expected shortfall through trades in WM.	1. Suppliers contract to cover shortfall by procuring supply- side flex or demand turn down	Suppliers buy or sell in intraday markets to ensure final VM position compliments actual GPP supply	Not Applicable	
		distributed to suppliers	DSR capability. More volume risk-averse suppliers take longer positions in VM. Offer consumes tariffs which trade off price and firmness.	2. Start to contract to cover any shortfall by procuring supply-side flex or demand turn-down.	2. Suppliers contract to cover shortfall by procuring supply- side flex or demand turn down			
				3. Suppliers unwind their likely unneeded WM positons.	3. Risk averse suppliers unwind their unneeded WM positions			
Interconnected Assets	No action - Interconnected assets excluded from GPP Participation		Status quo trading - expect reduction in liquidity because of renewables taken out of WM but non-GB demand not reduced.	1. Reduction in liquidity, without reducing non-GB demand, increased interconnected trades into GB.	1. GB >connected markets SRMC = interconnected flows into GB to manage shortfall. Reverse = interconnected assets flow out.	Not Applicable	Dependent on state of interconnected market	
				2. More pronounced reduction in liquidity. Increased interconnected trades out of GB.	<ol> <li>Split GPP may deflate WM price, expect GB SRMC<connected markets, and so flight of GB WM volumes over the interconnectors.</connected </li> </ol>			Status Quo
				3. More pronounced reduction in liquidity. increased interconnected trades out of GB.	3. Low WM price from excess. GB SRMC-connected markets and so GB WM volumes over the interconnectors.			
	Bids in at LRMC	No action	Refines position to facilitate Pool Operator's forecast.	No action	1. Receives strike price for 100% of volume.	2. Excess sold into VM; recieves at strike price (sold at SRMC, difference refunded to cons) COM		
Intermittent Renewables participating in Pool					2. Receives strike price for 100% of GPP volume.		Provide final operational or commercial data to Pool Operator	Pool operator is responsible for any imbalances caused by GPP generators.
					3. Receives strike price for 100% of GPP-contracted volume.		Poor Operator	by OFF generators.

- 3.18 Engagement with external stakeholders suggested that while a green power pool could be workable it would not improve on the status quo and could introduce additional complexity unnecessarily, particularly from an investor perspective. Participants also highlighted a range of deliverability risks and opportunities for gaming, including the risk that if prices in the pool were transparent, participants could potentially be undercut by generators with a long-run marginal cost lower than the prevalent weighted average.
- 3.19 It is also not clear that a GPP would address market issue 1 in table 3, i.e. decouple prices beyond the status quo through a continuation of the CfD mechanism. As with the split market, it is likely that any price differential between the two markets would be traded away, and it is also unclear how contracts might be equitably distributed on the demand-side. Our analysis and policy development has not been able to identify design features which resolve these issues.

#### Demand reduction interventions

- 3.20 Greater deployment of energy efficiency measures (both fabric insulation, as well as deployment of lower energy using or more resource efficient products) could permit high electrification whilst mitigating the impact on electricity markets. Demand reduction could reduce total energy system costs and reduce the rate at which system costs increase, if the capital costs of deploying demand reduction measures together with scheme costs are lower than the avoided costs in the electricity system.
- 3.21 The assessment has focussed not on whether more EDR (electricity demand reduction) overall should be deployed, but on whether electricity market reforms could help achieve a given optimal level. However, to provide context, the assessment has considered the scale of the challenge which is substantial. Figure 6 illustrates the departmental net zero consistent high electrification scenario, which shows demand could double from current levels by around 2040. This increase depends on the deployment rates of energy efficiency (approximated by the green wedge). De-risking this deployment and stretching further into the illustratively shaded red area (which approximates technical potential) reduces the scale of the challenge.



#### Figure 6 – Electricity demand sources

#### Source: Internal DESNZ analysis (2024)

- 3.22 Four main options have been considered, which could be complementary:
  - In the first policy option, demand reduction could continue to be deployed through government's existing end-use sector policy such as major capital delivery schemes, standards and regulation, or a supplier or distributor obligation. This has been done through schemes such as the Energy Company Obligation and the Industrial Energy Transformation Fund.
  - In the second policy option, we would introduce demand reduction into the capacity market, through an auction scheme which would reduce the level of future capacity procured where it would be more efficient to reduce demand instead.
  - In the third policy option, a bespoke pay-for-performance scheme or auction could be introduced which draws on similar verified based per-unit reductions as DSR schemes, providing an additional revenue stream for aggregators drawn from cost savings to the overall electricity system, and allowing DR to compete as a resource within the energy market.
  - In the fourth policy option, demand reduction could naturally be incentivised through other reforms under consideration in REMA, such as a supplier obligation.
- 3.23 The precise cost and benefits of a demand reduction intervention through electricity markets depend primarily on the delivery of energy efficiency measures through end use sector policies, the capital and scheme costs, the cost of capital support schemes and future network build costs. There is therefore substantial uncertainty around the benefit of intervention. However, to explore the potential impacts, the assessment has considered a wide variety of evidence which was probative of the market failures set out above.

- 3.24 Evidence was collected through engagement with specialist energy efficiency policy teams and wider research<sup>6</sup> on demand side consumer and business adoption barriers. This evidence suggested that many of these barriers do not stem specifically from electricity markets but are features of other markets. There are actions proposed to address them (for example, clearer standards; reforms to EPC methodology; certain regulations). However, it was also identified that some of these barriers manifested through greater costs in any decision to install energy efficiency which could be mitigated directly through any funding aspect, and/or indirectly by strengthening the incentives of aggregators and/or other electricity sector intermediaries to address them.
- 3.25 The assessment considered evidence on the efficacy of a previous EMR pilot scheme similar to our third option (the capacity market auction). The evaluation found that because of the way the scheme and the CM were designed, introducing EDR into the CM would unlikely have been viable due to primarily (i) higher cost per kW and (ii) issues participants faced with the EDR pilot likely increasing if measures entered the CM<sup>7.</sup> It was assessed that some contextual and scheme design changes might improve the value of the scheme, in particular: longer contracts (comparable to those given to T-4 CM participants), higher potential driven by higher electricity use given electrification, greater ability to stack revenue streams, increased electricity long run variable costs<sup>8</sup> and increased clarity around long term ambitions in the space together with recent policy in heat, buildings & industrial sectors providing some increased certainty for supply chains and investors.
- 3.26 The assessment has discounted options 2, 3 and 5 in Table 2 for energy demand reduction (options that would introduce competition into an existing market, create a new bespoke market, or drive demand reduction through other reforms REMA such as the supplier obligation). The basis for this is that additional intervention to support demand reduction through upstream electricity markets carries a number of value for money risks, and that any potential benefits of additional intervention upstream could instead be secured by building on existing downstream policy interventions in a less disruptive way. A number of risks were identified with upstream interventions:
  - Concerns of additionality and duplication given the existing/in development downstream policies for end-users and ongoing reforms to retail markets. There is a risk that an upstream intervention could support measures that have access to other support schemes or measures that would have come forward without additional incentives.
  - Complexity of integrating electricity demand reduction into existing markets. Electricity markets are complex, and the introduction of a new intervention, or the adaptation of an existing intervention to include demand reduction could have unintended consequences on the rest of the system.

<sup>7</sup> https://www.gov.uk/guidance/electricity-demand-reduction-pilot page 62

<sup>&</sup>lt;sup>6</sup> <u>https://www.gov.uk/cma-cases/consumer-protection-in-green-heating-and-insulation-sector</u> <u>IEA Markets-based Instruments for Energy Efficiency</u> (2017) <u>Facilitating Energy Efficiency in the Electricity System: Call for Evidence (2019)</u>

<sup>&</sup>lt;sup>8</sup> The 2022 Green book series shows the LRVC being 20--110% higher in 2035 vs 2016 (the year of the EDR phase II pilot), depending on the sector.

- A bespoke demand reduction intervention would not be technology neutral. There is therefore a risk that demand reduction measures are favoured against other technologies.
- Ensuring that demand reduction measures are fairly valued against alternatives would be complex.
- 3.27 For these reasons, upstream demand reduction options have been discounted at the long-listing stage as these options fail the value for money criteria. The demand reduction option that is taken forward to the short-list is strengthening existing departmental energy efficiency policies. This option would see the continuation of the Government's existing portfolio of energy efficiency policies, which will be taken forward outside of the REMA programme.
- 3.28 Our work on demand reduction within the REMA programme has also demonstrated the need to ensure that the power system impacts associated with demand reduction are sufficiently captured when assessing the impact of new downstream policy interventions. The implication of missing (or inconsistently capturing) an important element of costs or benefits is that we take sub-optimal policy decisions, particularly in relation to electricity security and flexibility.
- 3.29 There is an established Green Book methodology and assumptions for estimating the value of reductions in energy use in policy appraisal. These methods are based on using the Long Run Variable Cost (LRVC) of energy supply. Where an intervention is expected to have significant wider impacts, for example on fixed system costs or prices, the guidance recommends that detailed modelling should be developed to account for such impacts. The Department will review approaches in order to drive consistency and proportionality. Any improvements in the approach to measuring the impact of electricity demand reduction in policy appraisal would strengthen the value for money arguments for new or strengthened interventions to support demand reduction in downstream markets.

#### Short-list assessment

3.30 The assessment of candidate market failures within electricity markets found that all options other than continuing with existing approach to demand reduction deployment failed the REMA assessment criteria in comparison to our counterfactual argument. As such, the BAU approach has been taken forward to the short-listing stage without assessment, given we would maintain existing arrangements.

## Assessment of challenge 2 options

#### Overview and context

- 3.31 Challenge 2 is concerned with enabling rapid further investment in variable renewable energy generation (VRE). Rapidly deploying more VRE, which includes onshore and offshore wind and solar photovoltaics (PV), is critical to achieving the Government's ambition to decarbonise the power system by 2035, subject to security of supply. The Government's ambition is to have up to 50GW of offshore wind capacity installed by 2030, and up to 70GW of solar PV by 2035.
- 3.32 It is critical that our future market arrangements, including the Contracts for Difference (CfD) scheme, continue to support investment, and do so in a way that also supports system flexibility and operability. The design of CfDs can impact the investment and operational incentives faced by developers and generators and may interfere with some important market signals.
- 3.33 This section of the assessment outlines the advantages and disadvantages of the current CfD design, and how associated issues might best be addressed. The assessment articulates a 'market signals' framework, explaining how and why the current CfD design might distort investment and operational decisions, and how these could be resolved by different reforms. It also considers the potential impact of reforms on risk allocation, cost of capital, and system cost.
- 3.34 Based on these considerations, an assessment of the potential costs and benefits of different reform options is provided based on the REMA assessment criteria. Throughout this assessment we refer to findings from a research project commissioned from Frontier Economics and Cornwall Insight<sup>9</sup> (referred to hereafter as the 'Frontier research'), alongside other evidence sources.

#### Counterfactual and dependencies

- 3.35 The counterfactual scenario for this challenge is the continuation of the CfD scheme as currently designed (see Figure 7 for further detail). This involves:
  - Annual allocation rounds (ARs). These are competitive 'pay as clear' auctions with budgets and pots set by Government, and do not feature non-price factors. It is assumed Government sets auction parameters consistent with overall power sector and VRE deployment ambitions.
  - Contracts last 15 years and specify a fixed strike price indexed to CPI inflation.
  - For VRE, the Intermittent Market Reference Price (IMRP) is based on day ahead (DAH) wholesale auction prices. Payments are suspended during periods of negative IMRP.
  - Payments are based on metered output.
  - Rules on co-location of storage continue as set out in existing Low Carbon Contracts Company (LCCC) guidance.

<sup>&</sup>lt;sup>9</sup> Frontier Economics and Cornwall Insight – Market Signals and Renewable Investment, 2024
- 3.36 The counterfactual does not include the AR7 reforms mentioned in the 'Ongoing CfD reforms' of the REMA consultation, nor does the REMA option assessment assess the cost and benefits of those reforms.
- 3.37 The design of the CfD has strong dependencies on other aspects of market design, as shown by the systems map under zonal pricing in the Challenge 4 assessment counterfactual section (Figure 22). For example, if locational pricing were introduced, this would have significant implications for the calculation of the reference price.

#### Figure 7 – What is a CfD?

The Contract for Difference (CfD) is a long-term contractual arrangement between a low carbon electricity generator and the Low Carbon Contracts Company (the LCCC), a government-owned company. Eligible generators compete for contracts that provide a fixed price, determined through a pay-as-clear auction, for electricity generated over the duration of a 15-year contract. During periods when the wholesale market price falls below CfD generators' fixed price, referred to as their 'strike price', suppliers are levied to provide a top-up to CfD generators which equates to the difference between their awarded strike price and achieved wholesale price. A negative pricing rule was introduced for generators awarded contracts in Allocation Rounds 2 and 3, so that when the day ahead price is below zero for six or more consecutive hours, no CfD difference payments are made for any generation during that period. This rule was extended from Allocation Round 4 so that no difference payment is paid for any period when the day ahead price is negative.

The difference payments protect investors from periods of low (but not negative) wholesale market prices, which would otherwise have to be priced into investment decisions. Conversely, consumers are also protected from periods of high prices as generators are levied to repay money to the LCCC if market reference prices are higher than the strike price. This money is in turn passed back to suppliers and can be distributed to bill-payers in the form of bill savings.

Overall, the CfD is designed to attract new investment into low carbon generation by mitigating counterparty and price risk and thereby enabling developers to access lower cost capital, lowering the overall levelized cost of renewable electricity projects and helping us meet climate change targets at the lowest cost to consumers. The feedback we have received so far suggests a CfD-type scheme will continue to be the best tool to drive renewables investment.



# Rationale for intervention

- 3.38 Since its introduction, the CfD scheme has performed well at supporting investment in new VRE at low cost of capital. Deployment has been strong and strike prices for key technologies have fallen significantly<sup>10.</sup> Data published by the International Renewable Energy Agency (IRENA) shows the UK has among the lowest cost of capital for wind and solar PV projects in the world<sup>11.</sup> However, recent macro-economic inflationary pressures are impacting investment in renewable projects as seen in the challenges of large offshore wind projects taking final investment decisions, both in the UK and abroad.
- 3.39 Our analysis finds that revenue support is likely to continue to be needed. Due to VRE's cost structure, characterised by high upfront capital costs and low variable operation costs, they are vulnerable to price cannibalisation in wholesale markets as their penetration increases (market issue 4 in table 5 below), thereby creating revenue uncertainty.
- 3.40 The CfD currently mitigates this issue by topping up generators during periods of low (but not negative) wholesale price, whilst also protecting consumers during periods of high prices. However, if periods of negative prices become more frequent in future, the negative pricing rule would create revenue uncertainty risk for investors, which could affect the CfDs ability to keep cost of capital low and result in higher strike prices. Additionally, available evidence suggests the existing design of the CfD scheme may excessively shield generators from important market signals, with negative consequences for investment and operational decisions (market issue 4 in Table 5 below). The main market signals of concern for VRE are set out in Table 6 below.
- 3.41 As set out in Chapter 2, market design directs which risks are allocated to investors, and which are held by consumers (via government and suppliers). To ensure VRE assets are investible, it is necessary to understand how risks are allocated under different reform options. While exposing investors to risks may increase their cost of capital, risk exposure also incentivises investors to adjust their behaviour to efficiently manage risks and respond to market signals.
- 3.42 Our analysis suggests that, when considering our enduring market arrangements, the key risks faced by VRE investors are operational risks risks faced by investors once the asset is operational particularly revenue uncertainty risk. This revenue risk is further split into two main categories detailed below. Table 7 further separates price and volume risk into VRE relevant sub-drivers and their respective risk exposure under the current CfD arrangements.
  - Price Risk risk that the sale price of electricity that an asset can achieve is higher or lower than expected.
  - Volume Risk risk that volume of electricity that an asset can sell is higher or lower than expected.

<sup>&</sup>lt;sup>10</sup> See Evaluation of the Contracts for Difference scheme for details

https://www.gov.uk/government/publications/evaluation-of-the-contracts-for-difference-scheme<sup>11</sup> Anatolitis, V. et al. (2023) The cost of financing for renewable power. Available at:

https://www.irena.org/Publications/2023/May/The-cost-of-financing-for-renewable-power

#### Table 5 – Market issues and failures for VRE

#	Candidate market issue	Market failure in GB electricity markets	Intervention area
4	Revenue support contracts (e.g. CfD) distort operational and investment signals for renewables assets. This could increase overall system costs which is ultimately passed on to consumers.	Imperfect information and misaligned incentives. The fixed price linked to output payment of the CfD limits the extent generators face dispatch and alternative use signals. The incentives faced by CfD generators is at odds with the needs of the system, resulting in over generation and under provision of system services.	CfD with a strike price range, revenue cap and floor model, deemed CfD, capacity payment, supplementary reform options.
5	There is a risk that current market arrangements will not deliver the required new build renewable capacity to meet our decarbonisation targets.	Inability to fully recover fixed costs through energy markets leads to 'missing money', deterring investment in new renewable assets thereby allowing climate change negative externalities to persist as decarbonisation of power sector slows. Near-zero marginal cost of production: as the penetration of renewables increases, cost structures will lead to wholesale electricity prices falling to close to zero, more frequently during periods of low demand / high renewable output. This is termed 'price cannibalisation'.	CfD with a strike price range, revenue cap and floor model, deemed CfD, capacity payment, supplementary reform options.

#### Table 6 – Market signals for VRE

Type of signal	Signal	Description	How current CfD design impacts signal
Operational	Dispatch	Should a generator produce or curtail a marginal unit of power, at a given point in time?	Distortive Generators have an incentive to produce as much power as possible, regardless of system requirements or intraday prices, during all periods of non-negative Intermittent Market Reference Prices <sup>12</sup> <sup>13</sup> .
		Distortive During network constraints CfD generators will require turn down payments in the balancing mechanism (BM) equal to the foregone difference payment.	
			Distortive Generators are incentivised to all bid in the wholesale market in the same way ('herding'),

 <sup>&</sup>lt;sup>12</sup> The Intermittent Market Reference Price (IMRP) is a proxy figure for the wholesale price of electricity and it is calculated for each hour using the day ahead weighted average of EPEX and N2EX markets.
 <sup>13</sup> The existence and significance of this distortion is best described in <u>Newbery, D. (2021). Designing efficient</u> <u>Renewable Electricity Support Schemes. Energy Policy Research Group, University of Cambridge, 2021.</u>

Type of signal	Signal	Description	How current CfD design impacts signal
			leading to potentially damaging cliff edges when prices become negative due to the negative pricing rule, making it difficult for the system operator to manage the system. However, we currently do not have strong evidence to suggest herding behaviour is a significant driver of future system costs.
	Storage and flexibility	If co-located with flexibility, when should a generator charge and discharge the asset?	No significant impact Metering arrangements confirmed by the LCCC means a generator should be fully incentivised to charge and discharge co-located storage in accordance with market prices.
	Alternative use	What else could / should a generator do with the asset? For example, should they provide an ancillary service?	Distortive During non-negative day-ahead price periods, generators will only provide 'turn down' ancillary services where the revenue available from doing so exceeds their foregone difference payments, regardless of the true real time relative marginal system value of power versus the marginal system value from the provision of such a service.
	Trading	How should a generator trade their power?	Distortive Intermittent renewable generators have a strong incentive to trade exclusively in the day- ahead market to avoid basis risk <sup>14.</sup> This may negatively impact the ability of suppliers to hedge which in turn could lead to higher consumer costs. In addition, once the day ahead price clears positive, generators may face a distortive incentive to trade at negative intra-day prices.
Investment	Location	Where should a new project be located within GB?	Potentially distortive At present there are potentially some weak locational distortions that are caused by the CfD. The fixed strike price in all periods leads to minimal revenue incentive to locate in areas that have less renewable deployment, despite being beneficial for the overall system and assets potentially benefiting from higher prices in good local weather conditions.
	Project characteris tic	Which technology, what size? Should you	Potentially distortive The CfD system incentivises developers to maximise their potential to generate at all

<sup>&</sup>lt;sup>14</sup> Unpredictability in earnings related to variation in the difference between i) reference wholesale market price and ii) average capture price.

Type of signal	Signal	Description	How current CfD design impacts signal
		co-locate with storage? Should you invest in equipment to provide ancillary services?	times, regardless of wider market opportunities. Specifically, having payment linked to output with a fixed strike price in all periods may reduce incentives to invest in equipment to provide ancillary services.

#### Table 7 – Price and volume risk for VRE

Risk Category		Definition	Risk exposure under current CfD	
Price risk	Policy driven electricity price risk	Risk that policy changes result in electricity price changes.	Fully protected	
	Other electricity price risk	Risk that electricity prices are lower than expected for market reasons.		
	Basis risk	Risk that generators cannot achieve the reference wholesale price due to variability in output profile.	Almost full protection	
	Locational price risk	Risk that investors are exposed to changes in the value of the locational electricity price signal. In the case of locational pricing, the spread between local and system average price.	No locational price risk under current market (TNUoS provides some locational cost risk)	
Volume risk	Policy driven demand risk	Risk that average electricity demand is lower than expected due to policy-driven factors.	Not protected	
	Economic curtailment risk	Risk that asset cannot generate due to higher than expected economic curtailment – curtailment due to excess supply of generation.	Not protected	
	Locational volume risk	Risk that the network cannot physically accommodate a generator's power.	No locational volume risk under current market	

3.43 Resolving these distortions is important because they may lead to excess system costs, as the level of CfD-backed generation will make up an increasing proportion of the electricity market, from around 6% of generation today<sup>15</sup> to around 70% in 203516. The core function of wholesale power markets is to provide an operational signal to generators to produce power when their marginal cost of production is below the marginal benefit of power to consumers.

<sup>&</sup>lt;sup>15</sup> DESNZ calculations using LCCC CfD generation data for 2022

<sup>&</sup>lt;sup>16</sup> DESNZ net zero consistent modelling scenarios

- 3.44 Relative prices across wholesale and ancillary markets should reflect relative demand and supply conditions in these markets and ensure that generators consider the full opportunity cost of producing power in their dispatch and alternative use decisions. This is especially important in a system based on self-dispatch, as the system operator has limited time and technical capability to adjust the market outcome after gate closure.
- 3.45 The current CfD design distorts these signals by artificially fixing revenues achievable from producing power. This may produce a systematic bias in favour of dispatching power, under-provision of ancillary services, and excess system balancing requirements. This would show up in higher balancing and system costs, which are ultimately borne by consumers. The poor investment signals may lead to a sub-optimal capacity mix and spatial distribution of assets, leading to higher than necessary system costs.
- 3.46 The assessment has not modelled the cost impacts of these distortions. There is uncertainty about the extent to which they will be problematic for the future power system, but through engagement with National Grid ESO, we determined that these issues are sufficiently serious to warrant shortlisting reforms to resolve them.

# Options

3.47 The assessment has considered a range of options for the long-term future of the support scheme for VRE, as set out in Table 8 below. Government has previously ruled out adopting a supplier obligation or equivalent firm power auction model as the primary support mechanism for VRE; these options are not considered in this assessment.

#	Option name	Assessment style
A	CfD with a strike price range	Longlist: failed the 'best value for money' and 'investor confidence' assessment criteria
В	Revenue cap and floor	Longlist: failed the 'best value for money' and 'deliverability' assessment criteria
С	Deemed CfD	Shortlist
D	Capacity-based CfD	Shortlist
E	Supplementary reforms – partial CfD and reference price reform	Shortlist

#### Table 8 – Challenge 2 options

3.48 The remaining options provide optionality regarding risk allocation between investors and consumers. The net impacts of shortlisted options in part depend on reforms elsewhere in the REMA Programme, particularly wholesale market reforms. Therefore, it is important to ensure a range of potential risk allocations and compatibility with remaining wholesale market reform options. The next phase of the Programme will consider further how effective risk allocation can support the delivery of a cost-effective system while sufficiently de-risking investment in renewables to meet our decarbonisation objectives.

#### Long-list assessment

#### Strike Price Range

- 3.49 At the long list stage, further consideration of the strike price range option was ruled out. The main costs of this reform are increased price risk to VRE investors (as shown in Table 9), which would likely translate to higher cost of capital, higher overall system, and consumer costs. The extent of this increased risk would depend on the size of the range, and correlation between prices and output volumes.
- 3.50 The Frontier research modelled the distribution impact of potential Internal Rates of Return (IRR) for wind and solar investments under a strike price range. Frontier used synthetic draws of historical prices as a proxy for uncertainty around future wholesale prices. The modelling found a large impact on distributions of IRR even under a modest variation of +/- 5% strike price range. It is worth noting this did not account for price/volume correlation.
- 3.51 The assessment also concluded that a narrow strike price range would have little to no effect on resolving the distortions with the current design. This is because these distortions are likely to be consequential during periods of low wholesale prices, but under a narrow range CfD generators would still not be exposed to these prices. It is plausible that a wider range could resolve distortions, but this would have an unacceptably severe impact on revenue risk and expose investors to too much price risk.
- 3.52 For the above reasons, a strike price range is likely to increase system and consumer costs, relative to the counterfactual of the existing CfD, and thus fails the 'best value for money' and 'investor confidence' REMA assessment criteria.

<b>Risk Cat</b>	egory	Risk exposure
Price Policy driven electricity price risk		Partially protected – depends on range
risk	Other electricity price risk	
	Basis risk	Partially protected – depends on reference price
		design
	Locational price risk (only	Partially protected – depends on range
	relevant under zonal pricing)	
Volume	Policy driven demand risk	Not protected
risk	Economic curtailment risk	Not protected
	Locational volume risk (only	Depends on firm access rights
	relevant under zonal pricing)	

#### Table 9 – Strike Price Range Risk Allocation

#### Revenue cap and floor

3.53 At the long list stage, further consideration of the revenue cap and floor (RCF) option was ruled out. Under this option, generators would receive a long-term contract that guarantees a minimum amount of revenue (the floor) and limits the amount of revenue (the cap) they can achieve over a year. Revenues would be assessed by the LCCC

using generators' accounting data. The policy would not require the use of a reference price.

- 3.54 An assessment of potential costs and benefits, detailed below, suggests three key potential benefits i) improved dispatch, alternative use and trading operational signals, ii) protects investors from price cannibalisation, iii) sufficient revenue certainty for developers. Five key potential costs compared to the current CfD are i) accounting for gaming risks, ii) weakened consumer protection, iii) weakened locational investment signal under locational pricing, iv) disadvantaging smaller projects and v) introducing new operational and investment distortions.
- 3.55 If annual revenues fall within the cap and floor, this option would resolve the dispatch and alternative use distortions caused by the current CfD design, as generators would be fully exposed to market prices, and would not be incentivised to produce power to achieve additional support payments. This could help reduce balancing and operability costs by making VRE generators more responsive to system requirements.
- 3.56 As this option would not require a reference price, the trading signal distortion would be removed, which could improve liquidity and the functioning of intra-day markets. Increased exposure to wholesale prices could slightly improve investment signals, as developers may be incentivised to locate assets in areas that are anti-correlated with the overall generation fleet, enabling them to generate and retain revenues during periods of low overall GB output and high prices. Developers may also perceive improved incentives to invest in a wider variety of technologies and equipment under this model, as doing so allows them to profit from engaging in ancillary markets.

#### Reduced whole-system costs: lower constraint/balancing costs.





3.57 However, as noted in the Frontier<sup>17</sup> research, the revenue cap may itself distort dispatch incentives – if a generator anticipates the cap is likely to be binding in a given period, this may disincentivise further generation, even if further generation would be beneficial to the system. Furthermore, in periods where trading revenues are unlikely to reach the floor level, then the marginal revenue of generation is effectively zero (generators will end up with the floor whatever they do) which may also disincentive generation that the system requires. These distortions could be reduced through having 'soft' caps and floors. However, a 'soft' floor could increase investment risk and a 'soft' cap could significantly weaken consumer protection. These distortions could also be alleviated through additional design features such as availability requirements,

<sup>&</sup>lt;sup>17</sup> Frontier Economics and Cornwall Insight – Market Signals and Renewable Investment, 2024

but we have significant concerns about the deliverability of such requirements and their adaptability.

3.58 The RCF would protect investors from price cannibalisation as the floor payment guarantees a minimum level of revenue for their investment, regardless of wholesale market prices. In general, we expect the revenue floor could provide sufficient revenue certainty for final investment decisions and ensures the cost of capital is not prohibitive. As outlined in Table 10, relative to the current CfD design, a revenue cap and floor could decrease revenue risks, through reducing volume risk, and removing price risk under the floor. However, the overall impact of a RCF on revenue risk is uncertain; the Frontier research noted that this will depend on the size of the range, and the correlation of wholesale prices and output. Any form of 'soft floor', in which generators are only partially topped up to the floor during low wholesale prices, would likely increase revenue risk and lead to higher cost of capital.

<b>3</b> ,		Risk exposure between cap and floor	Risk exposure outside cap and floor
Price risk	Policy driven electricity price risk Other electricity price risk	Not protected	Fully protected
	Basis risk	No basis risk under this model	No basis risk under this model
	Locational price risk (only relevant under zonal pricing)	Not protected	Fully protected
Volume	Policy driven demand risk	Not protected	Fully protected
risk	Economic curtailment risk	Not protected	Fully protected
	Locational volume risk (only relevant under zonal pricing)	Not protected	Fully protected

3.59 The RCF is likely to provide weaker consumer protection from periods of high wholesale prices than the current CfD. The cap means that generators pay back either all or a proportion of their earnings beyond a set price. This prevents windfall profits and means that consumer prices are less affected by volatile gas prices (as supported assets' returns are not determined by the marginal plant). This shields consumers from excess profits. A soft cap would weaken this protection, as generators can retain a greater proportion of their profits. The extent to which the cap protects consumers would depend on how accurate the accounts provided by generator are. A key concern is that, as electricity can be traded multiple times and over multiple time periods before it is consumed, generators may be incentivised to transfer value (e.g. within a group structure) through their trading strategies, reducing revenues legitimately reported under a RCF. For interconnectors, revenues are regulated and transparent, which significantly reduces this gaming risk. Hence why an RCF has been successful in supporting interconnectors. However, this mitigation is not likely to be possible or proportionate for an RCF applied across a much larger number of projects and technology types, leaving a significant risk of gaming present. The opportunity for poor value for money is high, through higher support payments under the floor and poor consumer protection under the cap. For renewable assets the risks around value for money are also greater as there is less control over cap and floor levels at individual asset level due to the auction process.

- 3.60 Another concern with the RCF was compatibility with wholesale market reforms, particularly zonal pricing. There are greater challenges in sending locational signals through this model relative to the metered output or deemed CfD, and capacity-based CfD. As shown in Table 10, the RCF would expose generators to both locational price and volume risk when revenue is between the cap and floor, but would insulate generators from this risk when revenue is below the floor or above the cap. The key consideration for the interaction between the RCF and locational wholesale pricing is the auction design. Under a simple auction design that ranks bids by floor level (£/kW or £/kWh) it may not be possible to maintain a locational signal. The auction could favour generators with the lowest costs (lowest floor levels), rather than those in more valuable areas (with higher zonal wholesale market revenues). There is a risk that wholesale market revenues are not sufficient to reach the required floor for generators. If the floor is binding, this further dampens the locational investment signal introduced via zonal pricing as generators are indifferent to their expected wholesale market revenue (as the floor is aways paid). An alternative would be to introduce a locational signal within the RCF auction design, for example ranking bids by expected 'top-up'. However, this would add complexity, and delivery challenges may make this auction design choice infeasible.
- 3.61 The frequency of payment under the RCF may also be damaging for suppliers and smaller projects. The RCF needs to operate on an annual basis as seasonal differences in revenue means that cap and floor levels would be inaccurate if the reconciliation period was shorter. While it is possible for assets to claim interim top-ups, they might only need to submit full data yearly to limit administrative burden. This would lead to uncertain size of supplier obligation levy payments, both from the LCCC who might need to hold more money, and from suppliers who might need to pay higher reserve sums (increasing costs to consumers). Smaller assets currently relying on daily CfD subsidy payments to operate may also struggle with more limited payments if they rely on regular payments to service debt or to use as collateral for trades.
- 3.62 The RCF model could also introduce distortions to investment signals. Under the current CfD, allocation of contracts is on a £/MWh basis. This ensures developers have an in-built incentive to reduce the levelised cost of electricity of their projects, for example by weighing up maximising the load factor against minimising capital costs. However, competing for an annual revenue floor is likely to overly favour assets that have lower capital costs, because these assets will need a relatively lower revenue to cover their capital costs (and investor rate of return). This is beneficial to minimise system costs but could be problematic if overly favouring lower capital cost projects ignores the system benefits and additional renewable energy that higher capital cost projects might deliver. For example, capital costs due to greater in higher resource areas (e.g. greater wind speed but higher costs due to greater seabed depth), but the increase in output would outweigh the increased costs.
- 3.63 This problem could be partially alleviated through the auctioneer adjusting bids to account for each project's estimated load factors, and evaluating bids based on an estimated £/MWh basis. Alternatively, the bids from developers could be made on a £/MWh basis, with the auctioneer then calculating annual revenue floors by adjusting for estimated load factor. This would require the auctioneer to gather and assure extensive information about potential projects. This introduces additional complexity

into the auction process for both the administrator and developers, potentially increasing administrative burden and opportunity for gaming.

3.64 Due to the accounting gaming risks, the potential distortions to both operational and investment signals, and the possibility that the revenue cap may not protect consumers from volatile gas prices in practice, the revenue cap and floor model failed the 'best value for money' assessment criteria. It also failed against the 'deliverability' criteria due to payment processes administration and the additional auction design complexity that would be required to address potential dispatch distortions, zonal pricing compatibility issues and overly favouring lower capital cost projects.

# Reduced whole-system costs/deployment of mass low carbon power & flexibility: cost of capital



#### Figure 8 - Revenue cap and floor logic map<sup>18</sup>

Revenue cap and floor



<sup>&</sup>lt;sup>18</sup> Note that in logic maps throughout yellow boxes denote activities, green boxes short-term outputs, orange boxes medium-term outcomes, and purple boxes long-term impacts. Where connecting lines are red, this denotes an inhibiting effect.

### Short-list assessment

#### Deemed CfD

3.65 The deemed CfD separates support payments/clawback amount from an asset's metered generation. Deeming is the process of determining an asset's generation potential at any point reflecting 'live' conditions. There are different ways that this could be done, for example using site-specific weather and asset data to determine output. Subsidy difference payments would be determined using the same calculation as the existing CfD, except for replacing metered output with deemed output. The green shaded area in Figure 7 represents the Difference Payments. Under a deemed CfD, these would be calculated as –

*Difference payment = deemed generation x (strike price – reference price)* 

- 3.66 An assessment of potential costs and benefits, detailed below, suggests three potential benefits i) improved operational signals, ii) improved project characteristics investment signals, and iii) a continued level of consumer protection. Two potential costs compared to the current CfD are i) gaming risks, and ii) weakening the locational constraint investment signals under locational pricing.
- 3.67 A deemed CfD could significantly benefit system operation through resolving the operational distortions associated with the current CfD noted in Table 6, with the exception of the forward trading inefficiencies. There are many potential variations to this model, but under any version generators' dispatch and alternative use decisions would have no impact on their CfD difference payments while being 'deemed', so these market signals would be fully preserved. We judge that this could improve the efficiency of wholesale and ancillary markets, reduce costs in the balancing mechanism (BM), and system operator procurement costs of ancillary services.
- 3.68 The logic map (Figure 9) below shows the main mechanisms by which the policy could have benefits. Relative to the counterfactual, any deemed CfD model could lead to higher gross CfD payments, as the deemed amount may exceed metered output. It is unclear whether this increase would be netted out by decreases in costs elsewhere (e.g. Balancing Mechanism) and therefore whether it would lead to either similar or lower system costs overall.
- 3.69 Under the counterfactual, during periods of network constraints, CfD assets will tend to demand BM payments at least equal to their foregone CfD revenue to turn down generation. Where asset output is 'deemed', this foregone revenue is zero (as being constrained off has no impact on the deemed volume), and so BM bids from CfD assets should be at or close to zero, offsetting the higher gross CfD payments. Deemed models may also reduce the amount of redispatch required in balancing, as the wholesale market will be better at matching supply and demand prior to gate closure. The decreased BM costs from deemed generation in a locational pricing system need to be considered against the additional cost of a higher volume of CfD subsidy payments going to assets under deemed generation as they are guaranteed their strike price whenever they are able to generate, regardless of system constraints.
- 3.70 Whether assets consider their short run marginal costs (SRMC) is important for the benefits case and extent the deemed CfD addresses the dispatch distortions mentioned in Table 6. If assets do not self-curtail when prices are below their SRMC, then the dispatch benefits of a deemed CfD relative to the counterfactual (in which

payments are suspended during negative price periods) may be minimal. However, even when SRMC is equal to zero, assets may have a positive opportunity cost of producing power, as they forego revenues from providing ancillary services. Exposing assets to relative prices across markets should encourage generators to fully consider their opportunity cost of production and take dispatch decisions that benefit the system, lowering the costs of procuring ancillary services. As the deemed model would still require use of a reference price, it would likely not improve the trading inefficiency outlined in Table 6.

#### Causal chain summarising the operational benefits case of the deemed CfD



#### Causal chains summarising the dispatch efficiency benefits of the deemed CfD



- 3.71 'Deeming' may improve some elements of the project characteristics investment signal, as developers would be incentivised to innovate and invest in equipment to be able to participate in ancillary service markets and maximise their revenues. Due to the improved operational and investment signals mentioned above, the deemed CfD scores well against the 'best-value for money' and 'whole-system flexibility' assessment criteria.
- 3.72 Adopting a deemed CfD model could allow for the negative pricing rule in the current CfD to be removed, however, this is an outstanding policy design decision. It is likely that periods of negative pricing would occur less often under a deemed CfD than in the counterfactual, as under a deemed CfD assets would not be incentivised to dispatch power when prices clear below their SRMC, as they will obtain their difference payment whether they generate or not. Removing the negative pricing rule under a deemed CfD could reduce revenue risk and lead to lower cost of capital and therefore strike prices, as investors would no longer be exposed to uncertainty about the number of future negative price periods. Removing the rule could also further reduce the potential for 'herding' behaviour as there would be no additional price distortions in the market that could incentivise certain assets to operate in exactly the same way. However, the current negative pricing rule also protects consumers against the overbuilding of generation assets and from paying CfD generators when their supply is not needed. Therefore, any benefits could be offset by higher CfD subsidy costs due to an increase in the number of periods in which difference payments are made relative to the existing CfD with negative pricing rule. The net impact of these effects is uncertain.
- 3.73 The Frontier research concluded that the overall impact of a deemed CfD on revenue risk, relative to the counterfactual, is ambiguous and depends on several detailed

design factors, as set out in Table 11. All design options considered in the REMA consultation would protect investors from policy driven and other electricity price risks. Whether investors will be protected from locational price risk and different types of volume risk depends on policy design. Frontier noted that if future wholesale prices tend to fall below CfD strike prices, then a deemed CfD should reduce revenue volatility relative to the current CfD, although this may partially be offset if wholesale prices, and output levels are positively correlated. In general, we expect all deemed CfD models would provide sufficient revenue certainty for final investment decisions and ensure cost of capital is not prohibitive, therefore scoring well against the 'investor confidence' assessment criteria. Further work is required to assess potential impacts on cost of capital under different forms of a deemed CfD design.

- 3.74 Specific variations to the deemed CfD would have to be implemented if we wanted deemed CfD assets to be exposed to locational signals in a locational pricing system (see the REMA consultation for further details of these variations). Without such variations, deeming would not strengthen locational constraint investment signals, and the mechanism would continue to primarily reward high resource sites.
- 3.75 The deemed CfD model could be susceptible to gaming risks depending on the deemed methodology chosen. Gaming is when a developer or asset operator seeks to exploit policy design weaknesses to unduly profit at the expense of the scheme. For the deemed CfD, this may occur if assets can manipulate the data determining their deemed output, and subsequently their subsidy payments, or if they can manipulate the circumstances in which they would or would not receive payment. We are considering a range of deeming methodologies that trade-off robustness, administrative burden, and gaming risks. Data could include site-specific weather and asset data, or a theoretical or actual reference generator. The extent to which gaming could occur would impact the net benefits of this option. Given this uncertainty, the impacts on the 'deliverability' criteria were inconclusive.
- 3.76 At this stage of policy development, the assessment identified that the deemed CfD did not fail any of the assessment criteria in relation to how it addresses the market failures and market signal distortions outlined above. Another assessment will be undertaken once the deeming methodology and policy is further developed, and quantitative cost-benefit analysis can be produced to quantify net benefits.

Risk Cat	egory	Risk exposure	
Price Policy driven electricity price		Fully protected	
risk	risk		
	Other electricity price risk		
	Basis risk	Partial protected – depends on reference price	
		design	
	Locational price risk (only	Risk exposure depends on dCfD policy design	
	relevant under zonal pricing)		
Volume	Policy driven demand risk	Risk exposure depends on dCfD policy design	
risk	Economic curtailment risk	Risk exposure depends on dCfD policy design	
	Locational volume risk (only	Risk exposure depends on dCfD policy design	
	relevant under zonal pricing)		

#### Table 11 – Deemed CfD (dCfD) risk allocation

Note: for a national pricing interpretation of risk allocation ignore the locational price risk and locational volume risk rows.



#### Figure 9 - Deemed CfD – Logic Map

#### Capacity-based CfD

- 3.77 Under this model, new VRE generators would receive a fixed payment based on a £/MW basis, once operational, regardless of whether the asset is generating. Generators would operate on merchant terms, optimising their trading and operational strategies to maximise revenues across markets. A consumer protection mechanism would be introduced under this model to help shield consumers from periods of high wholesale prices and prevent excessive profits accruing to investors. For example, if wholesale market prices exceeded an administratively set strike price (£/MWh) the asset could be obliged to payback some or all of the difference (based on metered output, similar to current CfD arrangements).
- 3.78 An assessment of potential costs and benefits, detailed below, suggests four potential benefits i) improved operational signals, ii) improved project characteristics investment signals, iii) reduced support payments during network constraints, iv) improved locational investment signals under zonal pricing. Three potential costs compared to the current CfD are i) increased cost of capital, ii) favouring low CAPEX projects, and iii) weakened consumer protection. See capacity-based CfD Logic Map (Figure 10) below for a summary of these transmission mechanisms.
- 3.79 A capacity-based CfD could substantially benefit system operation though removing some of the operational distortions with the current CfD by exposing assets to dispatch, alternative-use and trading signals. As outlined in Table 12, assets would be exposed to price and volume risk, therefore only producing power when it is useful for the system when a unit of power exceeds their SRMC. Assets could be incentivised

to purchase equipment to reduce revenue risk (e.g. to provide ancillary services or colocating with storage) if expected revenues from these system service provisions exceed the upfront capital cost of their investment and allows them to submit more competitive bids during the auction process. This could reduce future operability costs by the system operator and increase system flexibility, scoring well against the 'best value for money' and 'whole-system flexibility' criteria. Not having a reference price or negative pricing rule to determine an asset's support payments means assets would not be incentivised to 'herd' their bids into day ahead wholesale markets at the zeroprice cut off, which may improve the effectiveness of the day ahead market at ensuring efficient dispatch and reduce operability costs for the system operator.

- 3.80 However, we are likely to introduce a reference price as part of the consumer protection mechanism. To minimise the trading operational inefficiencies resulting from the reference price, the reference price reform options discussed later in the chapter could be implemented. Given the reference price would be used infrequently to calculate clawback payments during periods of excessively high wholesale prices, the reference price distortions introduced through this mechanism are expected to be small.
- 3.81 Additional benefits include reduced support payments during periods of network constraints as assets would not export volumes to the grid when prices fall below their SRMC and therefore do not have to be paid to turn down in the BM. However, it is unclear whether this would reduce overall consumer costs as developers may seek to compensate for this lack of revenue by demanding higher capacity payments. The net impact on consumer costs depends on the level of competition in capacity payment auctions, auction design, and developer bidding behaviour.
- 3.82 Under zonal pricing, a capacity payment could also improve locational investment decisions as new assets would be fully exposed to locational volume and price risk. In theory, this should improve revenue signals for developers to site new projects in zones that are closer to demand centres and less likely to be network constrained. This could help improve the spatial distribution of renewable capacity across Great Britain, therefore reducing overall system costs. However, the net impact of a capacity-based CfD on the spatial distribution of renewable assets is uncertain due to non-market barriers constraining siting decisions e.g. planning, grid access, and land costs. Zonal pricing modelling by DESNZ and Ofgem have not considered a capacity-based CfD, so we do not have a quantitative assessment of its potential impact on siting.
- 3.83 There are three potential sources of costs of a capacity-based CfD model relative to the current CfD: increased cost of capital, favouring low capital cost projects, and weakened consumer protection. As shown in Table 12, a capacity-based CfD exposes generators to price and volume risk, though these risks are diminished as investors are provided with some revenue certainty through their fixed capacity payment. Although there is an effective revenue floor under this model, there is significant revenue uncertainty for all revenues above this floor. This may increase developers' overall cost of capital. Given wholesale market revenue uncertainty, it is possible developers would demand capacity payments to cover most or all the asset's annualised capital cost. How support costs compare under this model, the counterfactual and other options is unclear. We have not yet undertaken a full risk exposure assessment of this model as it was not analysed in the Frontier research project. Despite the cost of capital impacts uncertainty, this model does provide investors with considerable revenue certainty and

therefore scores well against the investor confidence criteria. The impacts on the 'best value for money' criteria are inconclusive at this stage.

#### Causal chains - mass deployment of low carbon power: revenue certainty



- 3.84 The capacity-based CfD could systematically favour low CAPEX projects because these assets will need lower revenue to cover their capital costs and be able to bid a lower capacity rate (£/MW) during auctions. This is beneficial to minimise system costs (ultimately paid by consumers) but could be problematic if overly favouring projects with lower capital costs ignores the system benefits and output potential of projects. For example, if costs are artificially reduced through undesirable site design decisions, such as locating solar arrays facing a sub-optimal direction or configuring wind turbines in such a way that does not maximise output. This problem could be mitigated if developers have good visibility of likely revenues across markets, considering what power they can produce and when, and if there is good competitive tension within the auction. In other words, assets with a high degree of system value (e.g. high load factors and ability to participate in a range of markets) should anticipate higher revenues and therefore should bid for lower capacity payments, making them more competitive in the auction. If, however, developers do not have sufficient visibility and confidence in revenues across markets and therefore are not reflecting these accurately in their bids, it may be necessary to mitigate against the risk of overly favouring low capital cost projects through introducing, for example, an 'availability factor' or other availability requirements. Any availability requirements could be used to (a) mitigate against the risk of overly favouring low capital cost projects in the auction, (b) encourage asset maintenance to a high standard, and (c) reward innovations to increase availability such as installation of onsite storage. However, availability requirements would add complexity to the policy design, risk introducing new distortions, and reduce the level of revenue certainty for investors. Further work is required to understand the extent to which developers are likely to account for wholesale and other revenues when submitting bids. Therefore, the impacts of this option against the 'best-value for money' and 'deliverability' criteria are inconclusive at this stage.
- 3.85 Consumer protection against high wholesale prices is expected to be strong but could be weaker under a capacity-based CfD than under a two-way CfD depending on design. During such periods, consumers would have to pay both the capacity payment and a portion of the high wholesale price to generators, rather than receiving net payments from generators as they do under a two-way CfD. We would seek to include a consumer protection mechanism to protect against this and ensure the option delivers the desired REMA outcome of a least-cost overall system. We think the best way to do this is to require generators to pay back all, or a proportion of the difference between a wholesale reference price and an administrative maximum wholesale price (both £/MWh basis) if the reference price exceeds this maximum level. How this would compare to consumer protection under our other options depends on a wide range of factors, including clawback parameters, wholesale market prices and strike price levels

in the counterfactual, which could be driven upwards by increased volume risk. Therefore, this option scores well against the 'best value for money' criteria at this stage.

#### Causal chains - consumer savings: shielding from windfall profits

Successful projects are paid a fixed amount based on installed capacity, whether generating or not

3.86 The assessment identified that the capacity-based CfD did not fail any of the REMA assessment criteria in relation to how it addresses the market failures and market signal distortions outlined above. Another assessment will be undertaken once the policy is further developed, and quantitative cost-benefit analysis can quantify net impacts.

#### Table 12 – capacity-based CfD risk allocation

Risk Cate	egory	Risk exposure
Price	Policy driven electricity price risk	Not protected **
risk	Other electricity price risk	
	Basis risk	Some basis risk under this model if introducing a
		reference price for the consumer protection
		mechanism
	Locational price risk (only	Not protected **
	relevant under zonal pricing)	
Volume	Policy driven demand risk	Not protected **
risk	Economic curtailment risk	Not protected **
	Locational volume risk (only	Not protected **
	relevant under zonal pricing)	

\*\* Risk diminished due to some revenue certainty from fixed capacity payment.





#### Supplementary reform options

3.87 The following reform options could address some of the operational and investment distortions associated with the current CfD design without changing the payment structure. These could be implemented in parallel with, or instead of, the payment structure reforms mentioned above.

#### Partial CfD payments

- 3.88 A partial CfD would retain the payment structure of the existing CfD but increases exposure to market signals by only covering a specified amount of each site's capacity under the CfD. The CfD portion of an asset's generation is reduced to below 100%. The remainder of the asset's generation is treated as merchant. The merchant portion is not subject to CfD difference payments, and therefore, is exposed to market signals. The intention would be to meter different parts of the site separately for the purposes of CfD settlement.
- 3.89 We need to do further work to understand if and how this would change behaviour in practice whether it would result in the two parts of the site responding differently to market signals. If it does, this option would remove the operational distortions for the merchant portion of a site's capacity, whilst maintaining the investment and operational distortions for the CfD portion. The extent to which the merchant portion sees reduced investment distortions will depend on wholesale and alternative market prices projections, and the scale of the site. In theory, smaller sites might not see enough opportunity to profit in other markets to invest in the technology required because of

the small share of generation exposed to alternative-use market signals. Larger sites may be able to achieve economies of scale and therefore invest in the infrastructure to enable the site to provide alternative system services.

- 3.90 One of the benefits of a partial CfD is that it would likely be more straightforward to implement compared to other reform options since it would involve relatively minor changes to the current CfD. Furthermore, it would also be straightforward to flex the CfD: merchant ratio to accommodate different technologies and changing markets. Government also has the option to increase the merchant ratio between auctions, establishing this progression at the outset so the investor is clear what terms they will be operating under and when. This option is also compatible with other REMA reform options, including locational wholesale market interventions, and a deemed CfD. Therefore, this option scored well on the 'deliverability' and 'adaptability' REMA assessment criteria.
- 3.91 Since the partial CfD does not tackle CfD-driven market inefficiencies, there is likely to be no behaviour change for a potentially significant proportion of generation as distortions would remain for the CfD portion of a site. We would also expect to see higher costs of capital, and therefore strike prices for the CfD portion to reflect the increased price risk for investors relative to the status quo. This option weakens consumer protection compared to the status quo as consumers would see less payback from generators in times of high prices, since only part of the site is under CfD terms. However, it does mean less CfD difference payments being paid to generator, reducing costs to consumer costs, the overall scoring against delivering 'best value for money' assessment criteria is inconclusive.
- 3.92 Ultimately, a partial CfD might appeal to some investors (particularly those pursuing this model already) but is likely to be a challenge for others. Further work is needed to understand the extent to which this option would sufficiently address the price cannibalisation market failure identified, which would inhibit investment in renewables. There may be implications for potential CfD participation if generators do not want to take on the merchant risk, which could impact investment in renewables. Therefore, the impacts on the 'investor confidence' assessment criteria are inconclusive.
- 3.93 The net cost impact of this option may depend on how generators utilise PPAs to help manage their risk. As shown in Table 13 the partial CfD increases investor's price risk exposure compared to the status quo. Further work is required to determine the net impacts of this option, particularly on cost of capital, strike prices and overall value for money.

#### CfD Reference Price Reform

3.94 The CfD's reference price influences a range of operational decisions, including whether to dispatch or store energy, and how to trade it. Without reforming the reference price methodology, shortlisted options may contribute to a lack of liquidity in forward markets. The reference price gives CfD generators a strong signal to sell power in the day ahead market to reduce basis risk. This has a negative impact on liquidity in forward markets as there is little incentive to hedge volumes ahead of time, impacting the ability of suppliers to hedge their demand.

- 3.95 The reference price can also distort dispatch decisions. For example, CfD generators can bid at, or close to, zero prices into the day ahead market and still receive top up payments. This means generators can sell power at negative prices in intra-day markets, receiving their strike price for power sold even though the market might be signalling a power surplus. Reforming the reference price to be based upon intraday prices would have minimal system benefits as it would incentivise trading in the intra-day market, making it very difficult for the system operator to ensure second-by-second balance of electricity supply and demand. This change would also not improve liquidity in forward markets.
- 3.96 Reforming the reference price period to include longer term forward prices could encourage CfD generators to trade more actively in forward markets and improve liquidity – addressing the trading dispatch inefficiency mentioned in Table 6. There are two refence price reform options under consideration. These reference price reforms could be implemented to any of the CfD options under consideration.
- 3.97 A hybrid reference price, where a portion of the traded volume would be set using a longer reference price, anywhere from a month ahead to a season ahead, whilst the remaining portion of generation would be set at the day ahead price.
- 3.98 This may increase the incentive for generators to hedge a portion of their generation ahead of time, while also maintaining the benefits of the day ahead reference price. This option would require further research and industry engagement to reach a final design and understand how well this would address dispatch distortions and forwards market illiquidity.
- 3.99 A 'forecastable' reference price period, calculated in a similar way to the existing reference price, but using a weighted volume average of more market price data, up to one week prior to delivery.
- 3.100 Increasing market exposure over a short period for generators could incentivise generators to seek ways to benefit from arbitrage between low and high wholesale prices and co-locate with storage. However, we are unsure whether this would change generator behaviour in practice, and it is unclear whether this would encourage more forwards trading, therefore reducing the liquidity problems in the forwards market.
- 3.101 As seen in Table 13, both reference price reform options increase price risk and basis risk for investors compared to the status quo as there is increased unpredictability of deviations between forward prices and outturn prices, and whether the plant's capture price matches the reference price. Therefore, we could expect the costs of capital and notional strike prices to increase relative to the status quo, though impacts could be limited, pointed out in the Frontier Report, given volume risk will remain the main driver for revenue risk. The extent to which these reforms will impact cost of capital depends on the length of the reference price period under the 'hybrid' reference price and which market prices are used in the 'forecastable' reference price period.
- 3.102 These options introduce greater wholesale price exposure within the reference period, therefore assets that are better able to produce at times of higher prices (i.e. when power is more valuable for the system) will be financially better rewarded. The longer the reference price period, the greater the exposure generators will have to variation in wholesale prices, and so the greater potential for differences in expected earnings, given differences in generators' output profiles. If generators are able to forecast these

periods and incorporate that in their strike price bids, this could lead to lower strike prices and lower costs to consumers. Therefore, scoring against the 'best value for money' assessment criteria was inconclusive since further analysis is required to estimate the net impacts of this option – balancing the increased cost of capital, improving forward markets trading, and lower strike prices from higher capture prices.

3.103 The assessment identified that the Supplementary Reform Options did not fail any of the REMA assessment criteria in relation to how they address the market failures and market signal distortions outlined above. Another assessment will be undertaken once a final package of policies is determined (given these options could be implemented in conjunction with payment structure reform options), and quantitative cost-benefit analysis can determine net impacts.

Risk Category		Risk exposure – partial CfD	Risk exposure – CfD with longer reference price
Price	Policy driven electricity price risk	Partially protected	Fully protected
risk	Other electricity price risk		
	Basis risk	Partially protected - depends on reference price design	Partially protected
	Locational price risk (only relevant under zonal pricing)	Partially protected	Partially protected
Volume	Policy driven demand risk	Not protected	Not protected
risk	Economic curtailment risk	Not protected	Not protected
	Locational volume risk (only relevant under zonal pricing)	Depends on access rights	Depends on access rights

#### Table 13 – Supplementary options risk allocation

# Assessment of challenge 3 options

# **Overview and Context**

- 3.104 Challenge 3 is concerned with managing the transition away from an unabated gasbased system to a flexible, secure, resilient, decarbonised electricity system. The transition will dramatically increase the need for low carbon flexible capacity to balance supply and demand and maintain the security and stability of the electricity system. As the economy electrifies and the penetration of renewables increases over time, the shape of residual demand (final consumption minus renewable generation), the load that must be met by non-renewable sources, will become increasingly variable and extreme<sup>19</sup>. This will require assets to respond more quickly – as fluctuations in wind and solar output are greater than the changes in demand which drive 'ramping' (how quickly output needs to change) requirements today.
- 3.105 Flexible assets which can provide this quick response will only generate when renewable output falls or to provide essential services to ensure the stability of the electricity system. As the capacity of renewables increases, there will be fewer periods

<sup>&</sup>lt;sup>19</sup> CCC / AFRY (2023) Net Zero Power and Hydrogen – Capacity Requirements for Flexibility

where these assets are operating to earn revenues, and these periods will become increasingly uncertain, driven by the intermittency of renewables. This means that these assets will need to obtain higher share of their revenue outside the wholesale market, potentially via the Capacity Market or other schemes.

3.106 For now, unabated gas generation continues to provide the main source of system flexibility and operability services. Meeting the Government's commitment for a fully decarbonised power sector by 2035 subject to security of supply will mean rapidly replacing the predominance of unabated gas through increasing the deployment of all forms and scales of low carbon flexible technologies and services that can serve a similar role. Nonetheless, several external analyses suggest that unabated gas generation will continue to have a role in the power sector in 2035, to help manage peaks in demand when renewable generation is low. The below table summarises what some of these sources say about the amount of unabated gas capacity required to deliver a secure, decarbonised power system in 2035.

Table 14: Minimum and maximum estimates of required unabated gas capacity, 2035, GW of installed capacity.

	CCC		FES		NIC	
	Estimate	Scenario	Estimate	Scenario	Estimate	Scenario
Minimum	12	Low, Central	25	Consumer Transformation	22	High Hydrogen
Maximum	13	High	27	System Transformation	28	Low Demand Flexibility

- 3.107 The above table only includes core Net Zero compliant scenarios from each source; results from sensitivity tests and model runs which go beyond the Government's current Net Zero commitments are excluded.
- 3.108 The majority of existing gas-fired power stations in the United Kingdom were commissioned in or before the year 2000, with many assets reaching the end of their planned lifetimes before 2030. The scope to prolong the life of such assets will be subject to commercial and technical limits. The exact rate at which this current capacity retires over the next ten years is crucial for determining how much, if any, newbuild unabated gas capacity will be needed to ensure security of supply while the electricity system decarbonises.
- 3.109 Based on a DESNZ-commissioned research project by Baringa, which will be published alongside the consultation, we expect that a limited amount of newbuild unabated gas capacity will be required in the short-term to offset retirements in the existing gas fleet. This is also consistent with other independent assessments by energy sector commentators and analysts. Without any newbuild unabated gas capacity, our current evidence suggests that it would not be possible to deliver the levels of unabated gas capacity in 2035 which FES and the NIC deploy in any of their core, Net Zero compliant pathways. Additionally, results from the Baringa research project indicate that some newbuild unabated gas capacity would be required to deliver

the levels of capacity seen in the CCC's 'Long Wind Drought' sensitivity scenario, in which a total of 25 GW of unabated gas capacity is installed by 2035.

- 3.110 While some uncertainty remains about the exact rate at which the existing gas fleet is expected to retire, the Government's evidence-based position is that it would be prudent to plan policy on the basis that some newbuild unabated gas capacity will need to be built in the short-term, to mitigate risks to security of supply in the late 2020s and early 2030s.
- 3.111 Low carbon flexible technologies, especially those capable of providing long-duration flexibility, will play an increasing role in ensuring security of supply. Supporting infrastructure, such as hydrogen and CO2 transport and storage networks, are key to deployment of these technologies and are therefore also crucial to maintaining security of supply. Due to infrastructure barriers set out below, these technologies are not expected scale up significantly until after 2030.
- 3.112 As the electricity system decarbonises, we will need a firm supply of flexible, low carbon electricity to maintain energy security. For short-duration flexible technologies, i.e. batteries and demand-side response (DSR), a range of external models estimate that the GB electricity system could require up to 55 GW of capacity by 2035<sup>20</sup>. For long-duration flexible technologies, i.e., hydrogen-to-power, gas CCS, unabated gas, and long-duration electricity storage (LDES), a range of external models estimate that the GB electricity system could require between 30 and 50 GW of capacity by 2035, with the aim for as possible of this capacity to be low carbon. The exact level of flexible capacity needed on the system is highly dependent on peak and annual demand, the future nature of system stress events and the deployment of renewables and nuclear capacity.
- 3.113 Balancing a predominately renewables-based system will require a mix of flexible solutions to effectively balance supply and demand over short-duration and long-duration timeframes. Different solutions have different relative strengths regarding the system services and characteristics they provide no solution provides them all. It is therefore crucial to ensure a balanced mix of low carbon flexible solutions come forward to maintain security of supply.

# Counterfactual

3.114 New capacity will be needed to both meet increasing demand but also to replace existing assets when they retire. This means that electricity generated from unabated gas will continue to be needed to ensure security of electricity, at least in the shortterm whilst low carbon alternatives scale up. Some of this need can be met by existing unabated gas plants, but to ensure a secure and reliable system, the government expects a limited amount of new build gas capacity will be required in the immediate term as it is the only mature technology capable of providing sustained flexible capacity. Procuring capacity both at a sufficient level and in a cost-effective way is not a given under the counterfactual, as we have seen declining liquidity in the CM in recent years.

<sup>&</sup>lt;sup>20</sup> External modelling of both short- and long-duration flexibility requirements includes work done by AFRY for the CCC's 'Net Zero Power and Hydrogen: Capacity Requirements for Flexibility', the NIC's Second National Infrastructure Assessment, and the National Grid ESO's 2023 Future Energy Scenarios.



Figure 11 – New build unabated gas capacity participation in T-4 auctions

- 3.115 Low carbon flexible technologies, especially those capable of providing long-duration flexibility, will play an increasing role in ensuring security of supply. Due to infrastructure barriers as set out below, they are not expected to scale-up significantly until after 2030.
- 3.116 The nature of future stress events is expected to change in the counterfactual, with potential implications for the amount of capacity we seek to target and procure, the shape of the risk we want to avoid and manage, and the type of capacity mix required in managing the risks. We commissioned LCP Delta<sup>21</sup> to explore this, and their study identified that it may be beneficial to move towards a combination of metrics for the reliability standard, depending on the future capacity mix. This would lead to higher procurement requirement to ensure capacity adequacy, other things being equal. Further empirical analysis is needed to fully determine what a future combined reliability standard should look like if adopted.

#### Dependencies/interactions with other policies

- 3.117 Providing the flexibility required to balance a predominantly renewables-based system in the 2030s will require a mix of low carbon flexible solutions to effectively balance supply and demand over short-duration and long-duration timeframes. Low carbon long-duration technologies such as power CCUS, H2P and LDES can provide low carbon generation over sustained days, weeks, or seasons during periods of low renewable output.
- 3.118 Currently, these three technologies face a range of barriers to deployment some are specific to individual technologies, and others are likely to exist for any First-of-a-Kind (FOAK) technology. These technologies, and more specifically initial plants with higher capital costs, are likely to struggle to come through under current market arrangements. In time, some technology specific barriers should be overcome with the

<sup>&</sup>lt;sup>21</sup> LCP Delta – Exploring Reliability Standard Metrics in a Net Zero Transition, 2024

roll out of infrastructure and commercialisation of nascent technologies. However, to mitigate these barriers and bring forward investment in these low carbon flexible technologies, the government is developing bespoke support mechanisms. In the net zero Strategy, we committed to supporting the deployment of power CCUS via the Dispatchable Power Agreement (DPA) and to supporting the delivery of the UK's first power CCUS project in the mid-2020s.

- 3.119 Consultations on the need for bespoke support for both H2P and LDES were published in December 2023 and January 2024, with a DPA style mechanism recommended as the lead option for H2P and a Revenue Cap and Floor for LDES.
- 3.120 The options considered through REMA are also designed to provide a route to transition away from bespoke support mechanisms and introduce competition between these technologies. The effectiveness of the REMA options in achieving competition will depend on the effectiveness of these policies at de-risking investment, technologies being sufficiently mature, and the roll out of enabling infrastructure (e.g. CO2 and hydrogen transport and storage infrastructure).

# Rationale for Intervention

3.121 As set out in the consultation document there are a number of factors preventing the deployment of flexible capacity needed on the system which are critical in minimising adverse risks in costs and security of supply. Table 15 identifies three market failures driving the issues described in this challenge and matches them to the REMA options which could be used to address them. The REMA options under considerations are designed to provide a route to transition away from bespoke support mechanisms (i.e. enduring solutions). We dismissed some REMA options via a longlisting stage where appropriate and conducted a fuller assessment on remaining options.

#	Market issue	Market failure in GB electricity markets	Intervention area
6	The system needs to manage the transition away from unabated natural gas. If natural gas assets are removed from the system too quickly it would create risks for security of supply.	Imperfect information - The role of unabated assets post-2035 is unclear, which leads to uncertainty in the investment / retirement case for these assets. This increases the risk of existing unabated gas assets closing earlier than expected.	<ol> <li>Optimised CM</li> <li>Targeted tender</li> <li>Strategic reserve</li> </ol>
7	Substantial capacity of low carbon flexibility is needed to meet our decarbonisation targets and provide a clear decarbonisation pathway for remaining fossil-fuelled assets but is not coming forward at the required rate. This would result in increased emissions	Positive externality / imperfect information / risk aversion – resulting in the 'missing money' problem limiting investment signals. This is further exacerbated by reduced running hours for flexible assets due to increased penetration of renewables.	<ol> <li>Optimised CM</li> <li>Cross-technology Revenue Cap and Floor</li> <li>Centralised Reliability Options CRO</li> </ol>

#### Table 15 – Challenge 3 market issues

	and missing decarbonisation targets.		
8	There is a risk that the current market arrangements will not deliver enough capacity able to provide sustained response, resulting in increased security of supply risks, (or increased emissions if unabated gas continues to provide these roles).	Positive externality – current market arrangements do not incentivise sustained response. Current prices incentivise e.g. storage assets to charge and discharge frequently, instead of having full capacity ahead of prolonged stress periods.	1. Optimised CM 2. Cross-technology Revenue Cap and Floor

# Options

#### Table 16 – Challenge 3 options

#	Option name	Assessment style
A	Centralised Reliability Options (CROs)	Longlist: failed Investor Confidence assessment criteria
В	Strategic Reserve (SR)	Longlist: failed Value for Money assessment criteria
С	Targeted Tender (TT)	Longlist: failed Value for Money assessment criteria
D	Optimised Capacity Market (CM) <sup>22</sup>	Shortlist
E	Cross-technology Revenue Cap and Floor	Longlist: failed Value for Money assessment criteria

#### Long-list assessment

- 3.122 Our longlisting assessment dismissed options where we identified that the underlying rationale for intervention was insufficiently strong or (relatedly) where all of responses except business as usual failed the assessment criteria, such that business as usual was preferable.
- 3.123 In the case of challenge 3, we are discounting Centralised Reliability Option as an alternative primary capacity mechanism to the CM, and Strategic Reserve and Targeted Tender as a supplementary add-on mechanism to the CM (having discounted them as an alternative primary mechanism following the first consultation). The Revenue Cap and Floor has been discounted as a future mechanism to enable competition between high capital, low carbon flexible technologies. Whilst the consultation document provides a discussion on our rationales, we provide an additional outline assessment here.

<sup>&</sup>lt;sup>22</sup> The 'CM with flex' option included in the first consultation document is now considered as part of 'Optimised Capacity Market option.

### Centralised Reliability Option

- 3.124 In the first REMA consultation, we consulted on Centralised Reliability Options (CROs) as a form of capacity mechanism which could be introduced as an alternative to the CM. CROs function as auctions for a financial instrument 'a call option' between capacity providers and the ESO. Successful capacity providers must be available to be called upon for delivery of pre-defined capacity, in return for a reliability premium determined by the auction. Providers participate in the wholesale market as normal but if the wholesale price rises above the pre-determined strike price (set administratively), generators pay back the difference for every MW of undelivered energy. In effect, capacity providers give up peak prices in exchange for the reliability premium and the incentive to provide capacity is signalled through the level of wholesale market pricing rather than targeting a system stress event.
- 3.125 CROs could theoretically provide a better incentive for generators to be available and offer more price stability in times of stress events. The majority of respondents (68%) agreed in the first REMA consultation that we should continue to explore CROs, although a number noted it was not their preferred option.
- 3.126 We have examined the evidence, and while we can see the theoretical potential of a CRO model in some areas, for example in terms of incentivising availability of capacity, we have concluded that there is insufficient evidence that a CRO model would meet GB system needs more effectively than the CM with modifications at this time. This is primarily due to our concerns that switching to a CRO would not support the scale of investment in new capacity we need to ensure we have enough low carbon flexible capacity to match supply to demand in an increasingly intermittent renewables-heavy system.
- 3.127 We have also been unable to conclude that any potential advantages of moving to a CRO would be enough to warrant a change from the CM. The potential advantages regarding availability may be achieved through changes to the CM (such as strengthening the penalties regime), and this could deliver similar benefits without the upheaval and disruption of changing the whole mechanism required to move to a CRO system. This option therefore fails to meet the success criteria on 'investor confidence'.
- 3.128 We are therefore not taking forward the option of a Centralised Reliability Option for further consideration at this time, and instead will focus on optimising the Capacity Market.

#### Strategic Reserve

3.129 A Strategic Reserve (SR) is a mechanism whereby an amount of capacity is contracted but held outside the market and dispatched only in times of system stress when market-based tools have been exhausted. We consulted on the option of a SR in the first REMA consultation and there was no support for its use as a primary mechanism to replace the CM. However, we also asked if there might be a role for a SR as a back-up mechanism to help ensure security of supply and a majority of those responding agreed that this was worth exploring. We therefore considered a SR as a supplementary add-on mechanism alongside a main mechanism only. We have explored several potential uses for a SR, including:

- providing a security of supply fall-back including during prolonged periods of low wind;
- aiding the transition away from gas in a managed way;
- supporting operability; and
- reducing costs of capacity adequacy.
- 3.130 Possible benefits of a SR were found to be that it could provide greater assurance on security of supply and offer an alternate role for high-carbon plants that operate only for very short periods of the year, taking them out of the CM. Although we can see these potential benefits of a SR in some future scenarios, pre-emptively introducing a SR without a good reason could lead to Government support being provided for plant that is ultimately not needed, and could have drawbacks such as adding complexity to and reducing liquidity in the CM. We also had concerns about the costs of taking capacity out of the wholesale market and paying for it to be operational only at times of system stress, which could drive the cost of maintaining a strategic reserve up significantly. This option therefore fails to meet the success criteria on 'best value for money'.
- 3.131 Ultimately, we believe our plans for a reformed CM are more likely to deliver the capacity we need while also supporting development of low carbon flex.
- 3.132 We are therefore not taking forward the option of a Strategic Reserve for further consideration at this time.

#### Targeted Tender

- 3.133 A targeted tender is a centrally coordinated process to secure the construction of a specified quantity of new capacity, which is determined to be needed to improve the balance of supply and demand. This differs from a bespoke mechanism to support specific technologies, as a targeted tender would be triggered by specific events rather than consistently supporting projects.
- 3.134 We consulted on this option in the last consultation and 63% of respondents agreed that we should not take it forward. However, in light of support for consideration of a SR as a supplementary capacity mechanism, we believed there was also merit in exploring how a form of targeted tender could be used to sit alongside and support a main security of supply mechanism.
- 3.135 A targeted tender could potentially be used in a range of circumstances, for example to procure capacity in specific regions, potentially with specific characteristics. However, we have examined the evidence and consider that existing arrangements are likely sufficient to deal with any circumstances that a targeted tender might be deployed in. For example, ESO already run tenders through the Pathfinders project, to procure ancillary services which are needed in specific locations.
- 3.136 Furthermore, there are drawbacks particularly related to cost effectiveness. A targeted tender would be aimed at new capacity, which has the potential to increase system costs (it may be cheaper to keep old capacity online). In many circumstances it would be difficult to justify in advance of need that new capacity is required, and to agree the amount which should be procured. In circumstances where the need is clear, the nature of a targeted tender may mean that there is a limited number of projects which

can fulfil the needs of the tender, and we are concerned about the effects of this on market power and competition. This could potentially be mitigated through a rigorous process for ensuring value for money, such as that undertaken within the interconnector cap and floor. However, this process may be complex and timely to establish, thereby reducing the flexibility and benefits of a targeted tender. This assessment concludes that a Targeted Tender has failed to meet the assessment criteria on 'best value for money'.

3.137 As such, and based on responses to our previous REMA consultation, we confirm our previous position, and are not taking forward the option of a Targeted Tender for further consideration.

#### Revenue Cap and Floor

- 3.138 We have explored whether there is a need for, and value in, using a Revenue Cap and Floor (RCF) as the enduring multi technology investment support mechanism to align support for low carbon long-duration flexible technologies (power CCUS, H2P and LDES). Under this proposal, projects would compete at auction to secure a contract with government, where a minimum revenue floor would be agreed. Successful projects would participate in existing electricity markets, including the CM, to secure revenues. If a project does not meet its revenue floor within the reconciliation period (agreed length of time over which revenues are assessed), government would provide a top-up. When the contract is agreed, a cap would also be set at a percentage above the floor, although there would be scope for revenues above the cap to be shared between government and the project. Where projects end the reconciliation period above the cap, they will pay back a proportion of this to government.
- 3.139 A RCF mechanism is already used to support interconnectors. Under a potential crosstechnology REMA RCF, we envisage eligible technologies competing to secure a contract and determine the level at which the revenue floor is set – this would be a different approach to the mechanism currently used to support interconnectors [and proposed for LDES], which allocates contracts through an administrative process.
- 3.140 Ultimately, we have discounted the proposed REMA RCF, for the reasons set out below.
- 3.141 Any revenue-based model such as the RCF comes with a risk of gaming, as cap and floor payments are calculated based on the revenues that a generator earns. There are a number of ways in which the revenues reported under the RCF could be manipulated, in order to receive a greater payment.
- 3.142 For interconnectors, revenues are regulated and transparent, which significantly reduces this gaming risk. Hence why an RCF has been successful in supporting interconnectors.
- 3.143 For dispatchable generators, the risk of gaming is greater than for interconnectors, as revenues are more uncertain and less transparent. Where a RCF supports a limited number of projects it may be possible to introduce additional safeguards that prevent gaming, and we are considering this further in the LDES context.
- 3.144 In addition, as set out in the H2P consultation, a RCF could potentially limit dispatch incentives for dispatchable assets if asset operators judge that they are likely to fall outside of the cap and floor, which could increase market price and costs to

consumers. Distortions are more likely to occur if there's a high degree of certainty that revenues during the reconciliation period will end below the floor. This is more likely to occur if the reconciliation period is limited or the revenue floor is set at a high level. Conversely however, an extended time gap between reconciliation periods or a lower floor level would reduce investability. Mitigations could be introduced to reduce the risk of dispatch distortions, for example, by 'softening' the floor or introducing performance standards on either availability or dispatch as a condition of receiving payments. Under the REMA RCF proposal, the floor would be set through a competitive, pay-as-clear auction. This approach risks setting a floor at a level that is higher than some projects require and may mean it is challenging to meet the floor on a merchant basis. This outcome may be poor value for money for government and could increase the risk of distorting the incentive for projects to dispatch.

- 3.145 Finally, there may be a risk that a RCF could distort other parts of the market by improving the investment case for high CAPEX assets over more cost-effective alternatives. This concern was raised by respondents to the first REMA consultation, many of whom disagreed that a RCF could be designed to enable competition between all flexible technologies. Some respondents also suggested that DSR and battery providers would struggle to participate in a RCF due to the significant pre-qualification expenditure required<sup>23</sup>.
- 3.146 Overall, the assessment concludes a Revenue Cap and Floor (RCF) fails to meet the assessment criteria on 'best value for money'. We have therefore decided to discount it as a mechanism to provide investment support for all low carbon long-duration flexible technologies (power CCUS, H2P and LDES).

# Short-list assessment

#### **Optimised Capacity Market**

- 3.147 We intend to retain the Capacity Market as the capacity adequacy mechanism and to evolve it to address future challenges. The costs and benefits of retaining and optimising the Capacity Market will need to be considered in more detail alongside the whole system impacts at a later stage of the REMA programme, to ensure that the interactions with other elements of our electricity market arrangements are appropriately considered.
- 3.148 In the first consultation we introduced options for reforming the CM auction design to better align the CM in to better facilitate the deployment of low carbon and flexible capacity. These included:
  - Split auction where technologies with different characteristics are procured separately through two or more auctions, which run sequentially with procurement targets set independently for each.
  - Single auction with multiple clearing prices where all technologies continue to compete in the same auction, but a mechanism is introduced to allow different clearing prices to be determined for specific characteristics. We have further explored how this could be achieved by setting a minimum procurement target (otherwise known as minima) for desirable characteristics.

<sup>&</sup>lt;sup>23</sup>Review of Electricity Market Arrangements - Summary of Responses, BEIS (2023)

- Single auction with multipliers where all technologies continue to compete in the same auction but technologies with desirable characteristics receive an augmented clearing price determined by a multiplier applied to the overall auction clearing price.
- 3.149 Through a research project<sup>24</sup> we have further gathered evidence on a) the main design choices for these options and their considerations at high level, b) potential implication on auction outcomes, and c) risks and unintended consequences. At this stage we do not have a preferred position on how desirable characteristics should be defined. The study looked at applying the auction designs by carbon intensity (low carbon vs carbon capacity), and by specific low carbon flexibility attributes (this was called CM with flex in the first consultation). For the latter, the study used 'response time' and 'sustained duration response' as possible ways to define low carbon flexibility attributes.
- 3.150 Qualitative assessment suggests there is a weak case to include response time in the auction because of potential overlaps/distortion with the balancing market. The choice of desirable characteristics could also affect the objective of the auction. An objective to send signals for low carbon capacity in general would have different implications for auction design than an objective to send signals for specific forms of low carbon flexibility. The objective of incorporating signals for low carbon capacity into the CM auction is to maximise the proportion of capacity which is met by low carbon technologies, subject to ensuring value for money. There is no specific volume of need but rather a desire to maximise low carbon capacity. In the case of flexibility, there is more of a specific need such that the marginal benefit of flexible capacity demonstrates diminishing returns. In other words, once sufficient flexibility of the desired type is present in the market, further flexible capacity is less valuable. This has implications for mitigation measures for the auction design which is discussed below.
- 3.151 We find that each of the three design options are associated with different benefits and risks. The multiplier design is associated with volume risk in terms of the level of low carbon capacity that will clear in an auction. This could lead to (a higher risk of) over or under procurement which comes at a cost to consumers. For this reason, it is discounted on the basis that it is unlikely to achieve our objectives.
- 3.152 A split auction and the single auction with minima both have the potential to be designed to increase the proportion of low carbon capacity clearing in the CM relative to the current design. A split sequential auction in which unsuccessful low carbon capacity can compete in the second 'remainder' auction is conceptually very similar to an auction with minima for low carbon capacity. Both allow scarcity for low carbon capacity to be reflected in a higher clearing price but also allow for low carbon capacity and carbon emitting plant to compete to deliver overall target capacity. Relative to the minima auction, a split sequential auction may introduce more risk of unintended consequences as bidders with low carbon capacity may identify an opportunity to bid strategically in the first low carbon auction.
- 3.153 The minima option is likely to have two practical advantages over split auction potential administrative simplicity associated with running one auction instead of more than one; and lower risk of strategic bidding. Under the minima, low carbon capacity would receive the greater of the clearing price set under the minima or the overarching

<sup>&</sup>lt;sup>24</sup> CM Alternative Auction Design, Baringa Partners

https://assets.publishing.service.gov.uk/media/65e3a3193f69450263035fc1/4-alternative-capacity-market-auctiondesign.pdf

clearing price. If the marginal unit of capacity in the overall auction happens to be a carbon emitting plant, all capacity would clear at the same price avoiding the potentially distortive signals to carbon vs low carbon capacity. The minima approach is therefore preferred over the split auction design, with a focus on introducing a minimum procurement target for desirable characteristics (minima).

- 3.154 All three of the auction design options will increase CM costs relative to the status quo design. This is because the objective of increasing low carbon capacity winning CM contracts is achieved by agreeing CM contracts that would have been out of merit within the status quo single auction design. However, this does not take into account the benefits of contracting low carbon flexible capacity which will support more flexible management of the system overall, and the reduction of costs of deploying low carbon capacity elsewhere in the market. Minimising inframarginal rent within an auction would be key in minimising overall CM costs. The study conducted so far suggested several areas for further exploration, which includes bidding method (sealed bids vs descending clock) and auction format (e.g. pay as bid vs pay as clear).
- In addition, the new auction design will come with risks which will have to be managed. 3.155 Split auctions increase concentration of auction competition as they split liquidity between each auction. An auction with multiple clearing prices also increases concentration within a sub-set of the auction. There are challenges in setting appropriate target capacity for the low carbon auction that maximises contribution of low carbon capacity while retaining competitive pressures. The lead time ahead of delivery presents an additional challenge. In the absence of an informed forward view of low carbon capacity pipelines, the risk could be mitigated by setting a conservative target capacity with a shallow demand curve. The conservative target capacity mitigates the risk of a very high clearing price or an auction that does not clear. The shallow demand curve can allow value for money capacity to clear in the auction, even above target capacity. If on the other hand the objective is to procure capacity with certain flexibility attributes, diminishing marginal returns on such additional capacity may imply the use of steep demand curves which reflect the limited value from procuring more capacity than is strictly needed<sup>25</sup>

# Logic map and causal chains

3.156 The logic map below (Figure 12) sets out some of the potential benefits associated with an Optimised CM. As well as delivering its primary objective of ensuring security of supply, we expect an Optimised CM to reduce whole system costs, support the deployment of mass low carbon power, and increase whole-system flexibility. The rest of this section sets out these underlying causal chains in more detail.

<sup>&</sup>lt;sup>25</sup> Response time flexibility requirements are relatively fixed with diminishing marginal returns from additional capacity above a level necessary for the ESO to balance the system effectively. While larger, the volume of sustained duration response on the system will also be relatively fixed, driven by the anticipated capacity gap during a period of low renewables output.







Increased whole-system flexibility and deployment of mass low carbon power: separate auctions/multipliers/multiple clearing prices



3.157 The modifications to the CM would primarily aim to deliver CM contracts to a greater number of low carbon, flexible assets, increasing whole-system flexibility and contributing to the deployment of low carbon flexible technologies. Note that the CM also supports an increase in flexibility through transitional arrangements for DSR.

#### Ensure security of supply: future pipeline of capacity



3.158 CM auctions support both newbuild and existing plant. New build plant receives longer CM agreements, which provides sufficient revenue certainty to enable financing, whilst existing firm plant can cover their end-of-life fixed operating costs (uneconomical plant which is unsuccessful at auction drops out). By meeting auction targets, the CM provides a future pipeline of firm capacity which can deliver security of supply.

#### Reduced whole-system costs: ensuring cost-effective supply



3.159 Auctions are designed to maximise competition and liquidity (e.g. through use of a descending clock mechanism), and CM payments dampen the frequency of scarcity pricing in the wholesale market. This ensures cost-effective supply. Some international markets (e.g. ERCOT, which operates an energy-only market) rely on scarcity pricing to deliver necessary investment in firm capacity, but this can lead to underinvestment and high costs for consumers – the CM effectively reduces scarcity pricing by a) ensuring sufficient investment, and b) providing the invested capacity with additional revenue that then means plant can offer lower wholesale market bids.

# Assessment of challenge 4 options

- 3.160 The current wholesale market arrangements were introduced in an era of large, centralised, fossil fuel-based generation located relatively close to demand centres. However, a future net zero wholesale market will be one which is renewables based alongside a range of smaller, distributed flexible assets.
- 3.161 Renewable assets are likely to locate where the requisite natural resources (e.g. wind) are most plentiful, and where they are able to obtain planning consents. These locations are often at the extremities of the network, further from centres of demand. Moreover, it is becoming increasingly difficult to keep the system operating dependably and securely as renewable generation is generally less suited to the provision of vital system services which are needed to keep the system balanced. We therefore need to ensure that the electricity system is better equipped for these new conditions.
- 3.162 The first REMA consultation described a number of challenges to successful system operation:
- 3.163 Lack of efficient locational investment and operational signals the current wholesale market has a single national price and currently the CfD and Capacity Market are not designed to send locational signals. The current locational signals sent through network charges are arguably too volatile and unpredictable to effectively influence where assets should be built. Factors outside of the market, like weather patterns and seabed leasing, are the main drivers for where renewables locate. The lack of efficient locational signals and the need for new network investment means the system operator is having to manage increasing amounts of locational constraints through redispatch in the Balancing Mechanism.
- 3.164 Limited temporal signals for flexibility as covered in the previous chapter, temporal flexibility (shifting when electricity is consumed or generated) is important for smoothing demand peaks and lowering system costs by reducing the requirement for generation and network build.
- 3.165 Current market arrangements may not incentivise investment in low carbon capacity with the right characteristics to provide system services it is unclear whether the market is sending the right signals to bring forward the deployment of assets required to support operability challenges (e.g. inertia).
- 3.166 Current market arrangements do not make efficient use of all assets on the system lack of clear visibility of generation and demand at all levels of the system is a key barrier to effectively integrating these assets into the system. Greater co-ordination is needed between the distribution networks and the ESO to improve asset visibility and the development and coordination of national and local markets.
- 3.167 Low wholesale market liquidity liquidity refers to the extent to which a market allows assets to be bought and sold at stable, transparent prices. A liquid market is needed in forward markets to allow suppliers to hedge the impact of volatile wholesale prices for consumers, allowing them to offer products such as fixed tariffs, which help consumers avoid exposure to price volatility. Ofgem are responsible for liquidity under current market arrangements, but the impact of liquidity is an important consideration for REMA.
- 3.168 Since that consultation, policy development has explored ways to address those challenges and evolved into an option set around five groups:
  - 1. Improving locational signals
  - 2. Improving temporal signals
  - 3. Improving balancing and ancillary services
  - 4. Improving local and national market co-ordination
  - 5. Improving market liquidity

## Counterfactual and dependencies

## Lack of locational signals

- 3.169 A renewables-based-system introduces new challenges for system operation, balancing and optimisation. The ESO undertakes a range of different balancing actions to manage the system, with constraint management being the largest single component (making up around 50% of all balancing costs on average between April 2018 and September 2023).
- 3.170 Constraint management is required where the electricity transmission system is unable to transmit power to the location of demand, for example due to thermal constraints where the amount of energy to flow from one region to another exceeds the capacity of the circuits connecting the two regions. In this situation, the ESO will take actions in the market to increase and decrease the amount of electricity at different locations on the network.
- 3.171 The propensity of variable renewable generation to locate at the extremities of the network far from centres of demand makes constraint management increasingly challenging and costly. As the deployment of renewables accelerates, we expect to see increased periods when there are physical constraints on the ability of the network to transport electricity, and when renewables have to be turned down to resolve local imbalances in supply and demand.
- 3.172 Managing the transfer of renewable generated electricity will require rapid expansion of the network. But alongside this we will need to send more efficient locational signals so that generation and demand locate and operate in ways which can lower system costs.
- 3.173 Balancing is already a substantial cost to the electricity system. From £1.2bn in 2018/19 (of which £0.7bn were constraint costs), costs increased to £4.1bn in 2022/23 (of which £1.8bn were constraint costs)<sup>26.</sup>

<sup>&</sup>lt;sup>26</sup> National Grid ESO, Monthly Balancing Services Summary (MBSS), 2022, <u>https://www.nationalgrideso.com/data-portal/mbss</u>



#### Figure 13 – Annual Balancing Costs

#### Source: National Grid ESO, Monthly Balancing Services Summary (MBSS), 2023

- 3.174 The very large increase in recent years was predominantly driven by high gas prices increasing the cost of balancing actions. However, there has been an increase in the volume of actions taken in the Balancing Mechanism since 2016/17, as shown in Figure 14. Accepted offer volumes grew from around 5TWh in 2016/17 to around 9TWh in 2022/23, and accepted bid volumes grew from around 8TWh in 2016/17 to around 12TWh in 2022/23. Volumes were particularly high in 2020/21 due to the Covid-19 lockdown which caused a sharp drop in electricity demand, a fall in thermal generation, and a rise in the proportion of generation from wind and solar sources. This energy mix provided lower system inertia<sup>27</sup> and NG ESO needed to take more balancing actions to ensure grid stability. This gave an insight into the characteristics and challenges arising from a renewables heavy system where nameplate capacity on aggregate would be able to meet demand, but the locations and intermittent nature of renewables results in a need to take action. Ultimately this proved a useful case study for the future electricity system and market design considerations.
- 3.175 We can also see from Figure 15 that around 90% of accepted offer volumes were from high-carbon gas and coal plants. This demonstrates the need for low carbon flexibility in the Balancing Mechanism, and the emissions impacts of increasing volumes of actions.

<sup>&</sup>lt;sup>27</sup> Many generators producing electricity for the grid have spinning parts – they rotate at the right frequency to help balance supply and demand and can spin faster or slower if needed. The kinetic energy 'stored' in these spinning parts is system inertia. If there's a sudden change in system frequency, these parts will carry on spinning – even if the generator itself has lost power – and slow down that change while the ESO control room restores balance.



Figure 14: Accepted offer/bid volumes in the Balancing Mechanism by technology

## Source: Raw data provided by Elexon with no warranty, all calculations by Aurora Energy Research

3.176 As more renewables come onto the system in the future, we expect the volume of actions required to manage constraints to increase, which will lead to higher balancing costs. ESO estimates utilising FES show that constraint costs could rise to between £2bn-4bn per year around 2030, see Figure 15<sup>28</sup>. This is from a starting point of £0.5-£1bn in 2022 which was estimated before the large rise in gas prices that led to actual costs in 2022 being around £2bn. They also estimate that carbon emissions from managing constraints could increase by around 2Mt CO2 on average annually between 2022 and 2031.

<sup>&</sup>lt;sup>28</sup> National Grid ESO, Modelled Constraint Costs NOA 2021/22 Refresh – August 2022





#### Source: National Grid ESO

3.177 These costs could be even higher if delays to network build persist. National Grid ESO analysis indicates that, if delays to network build persist, annual constraint costs could rise from around £2bn<sup>29</sup> per year in 2022 to around £8bn<sup>30</sup> per year (£80 per household per year) in the late 2020s<sup>31</sup> - see Figure 16. This estimate assumes a 3year delay to network build based on analysis conducted by FTI Consulting comparing planned and actual delivery of network reinforcement projects in Great Britain over RIIO 1, which suggests delivery was around 3-years later than planned in 2020/21.32 The analysis assumes this 3-year delay persists in the late 2020s. This is an appropriate, simplifying assumption, but delays may be higher given around four times as much new transmission network will be needed in the next seven years as was built since 1990.<sup>33</sup> However, the recently published Transmission Acceleration Action Plan aims to mitigate this risk by halving the timeline for building new transmission network infrastructure from 14 to 7 years.<sup>34</sup> These constraints could also continue beyond 2030 if network build fails to keep up with increasing demand and generation capacity coming onto the system.

<sup>&</sup>lt;sup>29</sup> National Grid ESO, Monthly Balancing Services Summary (MBSS), 2022

<sup>&</sup>lt;sup>30</sup> Undiscounted, 2022/23 prices.

<sup>&</sup>lt;sup>31</sup> The Department for Energy Security & Net Zero commissioned National Grid ESO to estimate constraint costs with a 3-year delay to network build. Limitations of this analysis are set out in the 'Risks and assumptions' section. <sup>32</sup> FTI Consulting (2022), Updated modelling results, slide 12,

<sup>&</sup>lt;sup>33</sup> Calculated using data held by the Department on the length of historic and future transmission networks.

<sup>&</sup>lt;sup>34</sup> Department for Energy Security & Net Zero (2023), Electricity networks: Transmission acceleration action plan,



Figure 16: Annual constraint costs with a 3-year delay, FES 2022, Leading the way, £ billions, undiscounted, 2022/23 prices, 2023-2042

## Source: DESNZ illustration of National Grid ESO analysis

- 3.178 Forecasting future constraint costs is highly uncertain, particularly because boundary capabilities may change due to reasons other than network reinforcement. This analysis provides a sense of scale rather than definitive results in individual years.
- 3.179 Under GB's current national pricing structure, the wholesale price of electricity does not vary for different market participants based on their location on the grid. This is because the wholesale price represents the result of "unconstrained dispatch" where network constraints are ignored, and it is assumed generation from any location on the network can reach demand at any location on the network. The provision of financially firm access rights to generators means they are compensated during those periods where parts of the network cannot take on their generation, but demand is available.
- 3.180 Factors such as connection times, load factors and planning permission play a pivotal role in the siting decisions of generation or storage. However, at present, Transmission Network Use of System (TNUoS) charges represent the primary way in which the market sends locational investment signals to market participants. TNUoS charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and Offshore.
- 3.181 TNUoS charges vary by location, with TNUoS tariffs split into 27 supply zones and 14 demand zones. The locational element of TNUoS charges is designed to be cost

reflective, capturing the estimated additional network investment associated with each asset. This provides an investment signal to generation assets to locate in zones with lower TNUoS charges. The impact of TNUoS on siting decisions in our current market structure is unclear. Many stakeholders cite the unpredictability of TNUoS as a limit to its effectiveness. In addition, neither of the key mechanisms for driving new generation capacity build - the Contracts for Difference and Capacity Market - are designed to send locational investment or operational signals.

3.182 A range of non-market policy actions are already underway outside of the REMA programme to help drive down balancing costs. This includes accelerating the pace of network build as well as actions to take a more coordinated and strategic approach to spatial planning to better match supply and demand (cross-refer to consultation for more detail). However, market-based solutions can help deliver additional benefits on top of network and planning policies. Market signals automatically 'translate' constraints into incentives for market participants to respond to. If price signals accurately reflect the system state, incentives are sent to generation and demand both on where to locate and, crucially, how to operate. Market signals can also help mitigate against the risks of delayed infrastructure delivery, or unforeseen network pressures, minimising costs for consumers until network build catches up with generation.

## Temporal signals

3.183 There are limited temporal signals for flexibility. Increases in intermittent generation and rising electricity demand will increase the need for flexibility to ensure we make the best use of the electricity system and keep consumer bills as low as possible. The current market arrangements do not maximise the incentives for flexible behaviour within the day. A discrepancy exists between the continuous nature of the electricity system (second by second matching of supply to demand) and imposed half hourly settlement periods. This results in a missing market for shorter-term temporal flexibility since generators and suppliers are not incentivised / rewarded over shorter time frames.

## Improving balancing and ancillary services

- 3.184 The BM was designed to operate on a settlement period by settlement period basis and is limited in its ability to address balancing issues that need to be managed across consecutive settlement periods. Intermittency, demand variability and battery storage are all likely to increase the frequency of such issues.
- 3.185 The BM is increasingly being used to implicitly co-optimise across a range of operational vectors (e.g., concerning reserve, response, and constraint management), with the ESO selecting the bids and offers that best contribute to security of supply. Decision-making can therefore appear opaque, providing a poor basis for competition and market entry.
- 3.186 Electricity markets can be prone to market power issues, for example via physical withholding. However, the current self-dispatch design opens up an opportunity for gaming the BM that is available even to generators that are not large enough to determine prices on their own. This could get worse as redispatch volumes increase.
- 3.187 Current market arrangements may not incentivise investment in low carbon capacity with the right characteristics to provide system services. Generation is no longer

providing the same suite of operability services that it used to by default to run the electricity system securely e.g. inertia.

3.188 Current market arrangements do not make efficient use of all assets on the system. As the system decarbonises, it is becoming more decentralised with increasing quantities of renewable generation and flexibility assets connecting to the distribution network. These assets can provide significant benefits to local and national markets. Unlocking this value will require sharper price signals that better reflect what the system needs across time and location as well as greater coordination across local and national markets so that revenues can be stacked.

## Liquidity

- 3.189 A liquid market is needed in forward markets to allow suppliers to hedge the impact of volatile wholesale prices for consumers, allowing them to offer products such as fixed tariffs, which help consumers avoid exposure to price volatility.
- 3.190 In the early years following liberalisation in 2000/2001, liquidity in the GB wholesale market rose to reasonable levels. But by 2004, it had fallen back to a level that was low compared to some (but not all) other electricity markets internationally. It has stayed broadly at this level ever since, with some degree of fluctuation. In recent years, liquidity has been falling further, particularly in forward markets. Market participants are concerned about this, as it makes it more challenging to manage their financial risks through hedging. Liquidity over all timeframes, but particularly in forward markets, fell sharply over winter 2022/23 to the lowest on record (partially due to high and volatile prices), but concerns have since eased somewhat as prices have stabilised.
- 3.191 It is a key consideration for REMA to ensure that liquidity is maintained under the transition to our future market arrangements, and that the market remains transparent and accessible to all participants. We have reviewed which REMA options could affect liquidity and have set these out in Appendix E.
- 3.192 As the electricity market regulator, Ofgem are responsible for ensuring that the GB wholesale electricity market, as it currently exists, is sufficiently liquid to provide efficient outcomes for consumers. Ofgem have recently published a call for input to gather industry views on current power market liquidity trends, issues and concerns and to explore the case for further market intervention to improve liquidity.

## Rationale for intervention

- 3.193 As set out in the consultation document, there are a number of features which could distort effective market functioning. Table 17 identifies core market failures relating to challenge 4 which drive the issues described in this challenge and matches these market failures to the options which address them. Given the interrelatedness of electricity market issues, some of the market failures highlighted below have also been identified under other challenges.
- 3.194 The market-based options covered by this chapter could incentivise generation and flexibility assets, as well as sources of demand, to build in suitable parts of the network where they are able to, and to operate more efficiently to lower system costs. Crucially, market-based approaches unlike non-market-based solutions such as planning or network build are able to send operational signals in addition to investment signals.

3.195 There remains a sufficiently convincing argument to continue to explore market-based solutions in conjunction with non-market-based solutions, to combat the growing levels of network congestion and resultant constraint costs (and more generally total balancing costs).

## Table 17: Challenge 4 market issues

#	Market issue Market failure in UK electricity			
		markets	Intervention area	
1a	Lack of locational operational signals for assets to respond to network constraints before the balancing mechanism. Most assets have firm access to the network so are compensated in those periods when energy cannot be delivered.	Negative externality/ imperfect information – the GB electricity market assigns the same value to all electricity irrespective of where it is produced or consumed. If locational signals sent by network charging and other non-market policy actions are not sufficient, this can lead to market inefficiencies. This is because generators and suppliers do not have to adequately consider system congestion and losses. These costs are socialised through BSUoS charges, meaning electricity consumers bear these costs.	1) Zonal Pricing 2) Nodal Pricing 3) Expanded measures for constraint management	
1b	Limited locational investment signals. Renewable capacity is often located far from demand. Generation capacity has outpaced network build.	Negative externality/ imperfect information – more efficient locational investment signals would ensure new assets and network users consider their impact on the network when deciding where to locate, minimising network reinforcement costs, generation capacity, and energy bills.	<ol> <li>1) Zonal Pricing</li> <li>2) Nodal</li> <li>Pricing</li> <li>3) Reformed</li> <li>Transmissio</li> <li>n Access</li> <li>4) Reformed</li> <li>Network</li> <li>Charging</li> <li>5)Locational</li> <li>CfD</li> <li>6) Locational</li> <li>CM</li> <li>7) Expanded</li> <li>measures for</li> <li>constraint</li> <li>management</li> </ol>	
2	The current market arrangements do not maximise the incentives for flexible behaviour within the day. Potential for improved local and national coordination of low carbon flex assets	Positive / negative externality / misaligned incentives – a discrepancy exists between the continuous nature of the electricity system (second by second matching of supply to demand) and imposed half hourly settlement periods. This results in a missing market for shorter-term temporal flexibility since generators and suppliers are	1) Shorter settlement periods 2) Shorter gate closure	

3a	Issues with dispatch and balancing	not incentivised/rewarded over shorter time frames. Shortening settlement periods and gate closure could enable flexible technologies (e.g. DSR) to take on a larger role in intraday balancing, leaving less residual balancing for the Electricity System Operator. Imperfect information BM decision- making can therefore appear opaque, providing a poor basis for competition and market entry. Inefficiencies - current market arrangements do not make efficient use of all assets on the system. Positive externality - centralised body buys reliability, therefore valuing sustained response and the right discharge behaviour. Misaligned incentives - the current self-dispatch design opens up an opportunity for gaming the BM that is available even to generators that are not large enough to determine prices on their own. This could get worse as redispatch volumes increase.	1) BM reform 2) Central dispatch 3) Local markets
3b	There is a risk that the current market arrangements will not deliver enough capacity that can provide flexibility / operability services (e.g. fast response, inertia), resulting in increased security of supply risks, (or increased emissions if unabated gas continues to provide these roles).	Positive externality / imperfect information / misaligned incentives– operability services such as inertia, frequency response, and voltage control are provided by certain assets when they generate and provide stability to the system. Current market arrangements do not value these services unless there is an imbalance through the Balancing Mechanism. Imperfect information - large uncertainty over the future capacity mix, timings, and scale for when certain technologies will come online, and therefore future demand for additional low carbon ancillary services.	1) Additional measures to maintain operability in a decarbonise d electricity system cost effectively 2) BM Reform

3.196 Interconnectors have and will continue to make up a significant proportion of the GB electricity capacity. In the Energy White Paper, published in December 2020, BEIS committed to "work with Ofgem, developers and our European partners to realise at least 18GW of interconnector capacity by 2030", over double the current capacity of 8.4GW. Given the significant role of interconnectors in the GB energy systems and the potential benefits for locational pricing for interconnectors, we have committed to continue to work closely with ESO, Ofgem and other stakeholders to identify and assess the potential options and assess the level of benefits which could be delivered under a national pricing scenario. This will include building on work already underway as well as identifying new options. It is not yet clear whether options could have the potential to send efficient locational operational or investment signals (i.e. address market issues 1a or 1b).

Transmission Mechanism of benefits from Locational Pricing

3.197 As stated above, we do see merit in continuing to consider market-based interventions such as locational pricing in addressing market challenges. The following schematic outlines the primary transmission mechanism through which benefits flow to consumers under locational pricing. An increase in locational price granularity compared to national pricing and removal of firm access rights across boundaries is required by both nodal & zonal pricing. This means that whilst the overall granularity of price areas and scale of resultant flows to consumers will vary between nodal and zonal pricing, the mechanisms by which consumers benefit is consistent. Not all of the transmission mechanisms discussed below lead to net economic gains, some of these flows will be offsetting and redistribute value around the system.

# Figure 17: Modelled Transmission Channels for Consumer Benefits under Locational Pricing



3.198 The above diagram focuses on those transmission channels modelled as part of the "System Benefits from Efficient Locational Signals" research study commissioned by DESNZ and conducted by LCP Delta & Grant Thornton<sup>35.</sup>. The three core flows not reflected in the above are implementation costs, which would negatively affect consumer benefits, demand side response and savings on generational & network

<sup>&</sup>lt;sup>35</sup> LCP Delta and Grant Thornton – System Benefits from Efficient Locational Signals, 2024

build costs, which would both positively affect consumer benefits. These elements are discussed in more detail under the zonal pricing logic map in Figure 25 in the shortlist assessment.

3.199 **Congestion Rent**: This represents the profit that domestic transmission network owners would earn based on the wholesale price differential between two connecting zones. Under locational pricing, producers only receive the marginal price within their node or zone. This is in contrast to national pricing, where producers receive the marginal price based on the national marginal plant. Electricity is therefore purchased at prices closer to the regional marginal cost of production. The surplus inframarginal rent which producers would benefit from under a single national price can then be transferred to consumer benefit (via transmission network owners) through congestion rents. Locational pricing therefore has the potential to pass on the benefits of low-cost renewables more fully onto consumers. The level of transfer in surplus will depend on several design decisions including the consideration of legacy arrangements for existing assets.



## Figure 18: Inframarginal Rents under National Pricing<sup>36</sup>

3.200 Under national pricing arrangements, the wholesale electricity price is set by the national marginal plant (the most expensive plant needed to meet demand). In the above diagram this would be generator 6. This leads to inframarginal rent for other generators, demonstrated by the shaded blue area (the difference in price between their own marginal price and the marginal price of the price-setting plant). This can raise consumer costs, though interactions with government support mechanisms such as CfD require careful consideration (as these assets will not receive the wholesale price, but rather a separate "strike price" determined at auction).

<sup>&</sup>lt;sup>36</sup> Stylised example to demonstrate concept of inframarginal rent. Does not reflect all market dynamics such as support payments or fixed price contracts.





- 3.201 Under zonal pricing, prices are instead set by the marginal plant within zones, which can reduce the inframarginal rent generators receive. In Zone A, generator 2 sets the price generator 1 receiving inframarginal rent (shown by the shaded blue area). In Zone B, part of the total demand is met by generation imported from Zone A, shown by the solid blue area. Generation imported from Zone A receives the lower clearing price of Zone A. This reduced rent (shown by the light green shaded area) can be transferred from generators back to consumers, reducing consumer bills. This represents a transfer from producers to consumers, the latter of which stand to benefit.
- 3.202 **Constraint Cost**: Defined as payments made to generators as result of being asked to turn-up or turn-down by the ESO. Locational pricing means that wholesale prices will be more reflective of the physical system i.e. that they will be higher in constrained areas and lower in non-constrained areas which increases dispatch efficiency. Market participants will also, where they are able to, make more locationally responsive siting decisions, locating in (e.g.) import-constrained areas, which reduces the volume of curtailment and lowers constraint and balancing costs. Additionally, under locational pricing, generators no longer have firm access across zonal/nodal boundaries meaning they are no longer entitled to turn down payments for congestion across zones. These constraint cost savings are not a 'pure' benefit as they are in part moved into the wholesale price given this price now accounts for constraints.

- 3.203 **Wholesale Cost**: This is simply the cost to consumers of paying generators the wholesale price. Whilst it may be counterintuitive in the first instance that the wholesale cost rises under locational pricing this is due to constraint costs effectively moving into wholesale prices from the BM given these prices now account for constraints. This increase in cost is slightly offset by the increased efficiency of accounting for constraints through the wholesale market.
- 3.204 **Policy costs**: The payments made to generators as a result of having policy support contracts such as CfDs and ROCs for both new and existing plants. Locational pricing would lead to lower prices in certain areas (e.g. in areas where there was a surplus of renewable generation as well as network constraints). This means that LCCC would need to provide higher top-up payments to CfD plant located in those areas to continue to meet their strike prices (assuming the reference price is local and not a national average). Future CM payments could also increase in some cases as dispatchable plants in some areas could face lower revenues, requiring a higher capacity payment to remain online.

## **Options (Location)**

## Table 18: Challenge 4 locational options

#	Option name	Assessment style
A	Reformed Transmission Charging	Shortlist
В	Reformed Transmission Access	Shortlist
С	Zonal Pricing	Shortlist
D	Nodal Pricing	Longlist: Failed critical success factor on Investor Confidence & Deliverability
E	Locational Capacity Market (CM)	Longlist: failed critical success factor on Value for Money

- 3.205 Our longlisting assessment dismissed options where we identified that the underlying rationale for intervention was insufficiently strong or where a critical success factor was not met. In regard to options for improving locational signals, we have discounted both nodal pricing and locational CM.
- 3.206 A fuller assessment of the locational CfD will only be undertaken should the option be utilised as a supporting change. See Option F under Challenge 4 of the consultation document for further details.

## **Reformed Transmission Charging**

- 3.207 As outlined in the consultation document, network charges are used by Ofgem to recover the costs of managing electricity networks. Ofgem are currently in the process of reviewing network charging arrangements, to ensure that current approaches remain fit for purpose and align with wider REMA reforms.
- 3.208 This includes a longer-term strategic review of transmission network charges (TNUoS), on which Ofgem recently published an open letter. This letter sets out initial thinking on the future role and design of TNUoS, and why reform may be required. One of the questions being considered is the role of locational signals in network charging reform.

A locational investment signal is already sent through TNUoS as one component of the charge differs by location, with 27 different zones for generation and 14 different zones for demand. However, the effectiveness of the investment signal sent through TNUoS is unclear at present. Ofgem are continuing to develop options for reform, considering a range of potential reform objectives. Notably this letter does state that signals sent through TNUoS should solely seek to influence the investment decisions of system users and not real-time operation.

3.209 We will continue work with Ofgem to consider options for reform to network charging in the next phase of the REMA programme. Ofgem and DESNZ have agreed to work on the programme of long-term TNUoS reform to the same timeframes as the REMA process, to ensure that decisions on the two can be taken together, given the interlinkages. In the next phase of REMA, we will carefully consider how options for reform would interact with existing charging arrangements, in particular the network charging discounts for Energy Intensive Industries<sup>37</sup>

<sup>&</sup>lt;sup>37</sup> Government response: British Industry Supercharger Network Charging Compensation Scheme 2023,

## **Reformed Transmission Access**

#### Figure 20: Reformed Transmission Access Logic Map

#### Transmission access reform



## Reformed Transmission Access: Key Causal Chains:

#### Agnostic allocation of access rights – Reduced whole system cost



3.210 If implemented, an agnostic allocation of transmission network access rights to new generation assets may reduce whole system costs by reducing the need for network build out as assets will be discouraged from locating in site where firm access rights are scarce.

Unintended consequence: ESO constrains down firm users in BM – Increased whole system costs



3.211 In the scenario that some assets are without firm access rights, the system operator has to constrain down firm access users in the balancing mechanism if needed. This may increase whole system costs by unintentionally creating a two-tier balancing system in the scenario that a more expensive asset holds firm access rights, creating inefficient BM dispatch if said asset is fossil fuel based.

#### Unintended consequence: Unavailability of FAR – Increased whole system costs



3.212 Under the implementation of transmission access rights reform, the unavailability of firm access rights may lead to higher cost of capital and ultimately increase whole system costs.

## **Zonal pricing**

- 3.213 As outlined in the first REMA consultation zonal pricing would split the GB market into clearly defined zones. The boundaries of said zones would be drawn to reflect where major transmission network constraints occur. Each zone has a single price which (like the current single national price) assumes no network constraints within the zone. Zonal pricing is well-precedented internationally, with various forms of zonal pricing currently implemented in the Nordic countries and Italy.
- 3.214 Our assessment acknowledges zonal pricing does not represent a singular well defined market reform. There are numerous forms of zonal pricing, with the exact implementation of zonal pricing having the potential to greatly change both the costs and benefits of such a market reform. Some of what our assessment currently views as the key design decisions have been outlined in Challenge 4 and Appendix 4 of the consultation. A position on the preferred form of zonal pricing has not been established by our assessment.

3.215 To explore the interactions and system dynamics of the locational pricing options captured by challenge 4 we have utilised a systems map approach. This allows dependencies with other policies to be easily identified and consequences of a given decision accounted for. The national pricing systems map depicts a simplified version of the current electricity market, with the existing CfD model. Chosen dependencies highlight the impact of a single wholesale price for GB. The zonal pricing systems map is a simplification of a potential zonal electricity market, with dependencies depicted under a constrained zone and an unconstrained zone.

## Figure 21: National Pricing Systems Map



National Pricing - Systems Map



#### Figure 22: Zonal Pricing Systems Map

- 3.216 As shown above under national pricing there is a single wholesale price for GB regardless of location or constraints, and assets also have firm access rights. Additionally, the above demonstrates that generation or storage assets receiving government support will have altered responses to this price signal relative to merchant plants. Under locational pricing there will be multiple price areas, the removal of cross border firm access rights, and the price within a given zone will depend on the balance of supply, demand, and network capacity (under a minimum of two zones as shown above). Based on our current system of marginal pricing this means generation and storage assets are no longer topped up to what would have been the marginal price under national pricing. Consumers instead pay closer to the regional marginal price of generation.
- 3.217 The resultant consumer benefit will be affected by decisions around legacy arrangements of existing assets and design of wider policy support, as locational pricing has an impact on risk for generators. As a result, policy decisions will need to be made on how best to mitigate any potential cost of capital increases.

- 3.218 The systems mapping exercise also identifies several key policy areas that affect the "size of the prize" from locational pricing (or that locational pricing affects). Decisions taken on future CfD and CM policy will alter the effectiveness of locationally focused policies as they have the potential to shield or expose a large proportion of future assets from/to these signals. Policy decisions on network build will also affect the "size of the prize" from greater locational signals through altering the volume of constraints faced by the system.
- 3.219 For the CfD, key design decisions will be required on the reference price, negative pricing rule and overall auction design. The impact of these decisions varies depending on if the future design of the CfD retains the link between metered output and payment. Locational pricing also has important implications for other assets. While competitive support schemes should be able to pass through the locational signals from the wholesale market, depending on the location of an asset, its profitability could be positively or negatively affected. Plants in lower price areas have the potential to put upward pressure on prices in the CM. All of these dependencies will be explored further in the next phase of REMA.

Costs and benefits of zonal pricing modelling

## Key Takeaways from Zonal Pricing Analysis

1. Majority of modelled benefits stem from <u>better operation of the system</u>, including the more efficient use of interconnectors.

In the scenario where redispatch inefficiencies are assumed in the national pricing counterfactual, system cost reductions from moving to locational pricing over 2030-2050 increase by £10bn, to a total of £15bn driven by operational efficiency savings. This is a result of interconnectors and storage being used more efficiently under locational pricing to help manage rather than exacerbate network constraints.

## 2. Locational pricing will see significant transfers between producers and consumers, with consumers benefiting greatly.

Analysis shows a consumer benefit of  $\pounds 25 - \pounds 60$ bn from zonal pricing over 2030 – 2050. Assuming these savings are fully passed through, this could equate to an average consumer benefit of  $\pounds 20 - \pounds 45$ pa per household over 2030 - 2050. With the transfer between producers and consumers heavily dependent on policy design.

## 3. Zonal Pricing has the potential to lead to <u>savings for the typical</u> <u>household in all regions</u>.

With the degree of variation between regions being highly dependent on policy design. Price differentials described below are of similar magnitude to the existing differences in typical household electricity bills.

Numerous sensitivities around the future makeup of the power sector as well as how locational pricing could be implemented support the continued examination of zonal pricing.

- 3.220 DESNZ commissioned analysis by LCP Delta & Grant Thornton shows the system benefits of zonal pricing fall within the range of £5-15bn over 2030-2050, and that consumer benefits can be up to £25-60bn over the same period. With the average benefit per household range presented above being a simple yearly average. Calculated by apportioning the total consumer benefit figure by domestic electricity demand then dividing by the number of households. These system benefits are similar in magnitude to modelling undertaken by Ofgem (c.£5-15bn system savings over 2025-2040). These figures are designed to give a sense of scale of change and do not capture all costs, such as cost of capital impacts, or all savings, such as reduced network & generation expenditure. These results do however add to the body of evidence that indicates there is merit in the further examination and more comprehensive analysis of zonal pricing.
- 3.221 As a move to zonal pricing would be subject to numerous uncertainties, the analysis sought to conduct numerous sensitivities around the future makeup of the power sector as well as how zonal pricing could be implemented. The core scenario used in this study does not represent DESNZ's preferred or most likely view of how the future system will look. It has been chosen as the core scenario for this analysis as a representative scenario to evaluate the possible impacts of moving to zonal pricing and as a starting point for comparison against the different scenarios explored in the report.



#### Figure 23: Overview of core quantified and unquantified costs and benefits

- 3.222 Evidence on impacts to the cost of capital from international markets is inconclusive. However, there have been a range of external estimates of potential cost of capital increases under locational pricing in GB, ranging from little impact (0-1%) to high impact (up to 3% over a decades-long period). As noted in the consultation, the final impact on the cost of capital has significant dependency on precise policy design and the choices over incidence and bearers of risk. Our view is that an increase as high as 3% is very unlikely under the market designs being taken forward by REMA, and these higher external estimates are often underpinned by unfavourable assumptions with respect to the level of assumed risk exposure.
- 3.223 The primary driver of the range of system and consumer savings are the assumptions made around treatment of interconnectors and broader redispatch inefficiencies outlined in Table 18. In the "Full Operational Impacts" scenario outlined below, system

cost reductions from moving to locational pricing over 2030-2050 increase by £10bn, to a total of £15bn, with this change driven by greater operational efficiency savings.

- 3.224 This is a result of interconnectors and storage being used more efficiently under locational pricing to help manage rather than, at times, exacerbate network constraints.
- 3.225 What is assumed about the counterfactual has a significant impact in the overall effectiveness of locational pricing. This range of results makes clear the importance of developing a robust counterfactual scenario to zonal pricing in the next phase of REMA, as it is not only the policy design of zonal pricing itself that heavily influences the conclusions of such modelling exercises but what the point of comparison is.
- 3.226 Modelling a wide range of scenarios has also helped provide a better understanding of the importance around the degree to which plants are able to relocate, these are described in Table 18 below.

## Table 18 – Summary of modelled scenarios

Scenario	Demand and Capacity	Cost of Capital	Network Build	CfD	Interconnectors in counterfactual	Batteries in counterfactual	BM Uplift	Offshore wind locational restriction	System benefits (2030-2050) (£bn)	Consumer benefits (2030-2050 (£bn)
Core – DESNZ Net Zero Higher Demand	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction	5	25
No Interconnect ors in Locational Balancing	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction	15	50
No interconnect ors and limited storage in locational balancing	DESNZ Net Zero Lower demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Limited participation in locational balancing	Bid up to marginal unit	Lower restriction	15	50
Full Operational Impacts	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Cannot participate in locational balancing	Limited participation in locational balancing	Bid up to marginal unit + uplift	Lower restriction	15	60
Network reinforceme nt 3-year delay	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND with 3-year delay	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction	5	25
CfD partially exposed to locational signals	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Partial exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Lower restriction	5	25
Higher offshore wind restriction	DESNZ Net Zero Higher demand	Generation Cost Report	NOA7 +HND	Full exposure to locational pricing	Fully participate in locational balancing	Fully participate in locational balancing	Bid up to marginal unit	Higher restriction	5	25

\*Note that LCP also explored a lower demand scenario as an additional sensitivity, however the combination of modelled demand and network capacity is unlikely to be cost optimal and as such has not been presented above.

3.227 Offshore wind is likely to be a key technology in the future system and provide the bulk of generation technology. Given its importance to the system, where offshore wind farms can locate, and any restrictions on this, is important to account for when examining locational pricing.

- 3.228 Overall, results show that with additional restrictions on where offshore wind can locate, the system benefits of moving to locational pricing slightly increase by £1.5bn over 2030-2050, compared to the core scenarios with less restrictions on where offshore wind can locate. Whilst this may seem counterintuitive, this result is driven by the locational pricing signal incentivising more movement of other generation types in response to the more restrictive offshore wind locations. Other technologies now face a stronger price signal in response to offshore wind not being able to move, creating incentives to take advantage of higher priced zones as a result of constraints. The key difference between the two scenarios is a larger decrease in constraint costs when moving to locational pricing as a result of the network being more constrained in the national pricing counterfactual. It is important to note that consumer benefits decrease slightly by £0.8bn in this scenario due to the higher constraints from the more restricted offshore wind scenario. This finding reinforces the importance of taking a holistic approach, as response to price signals and what this means for the overall system will vary greatly by asset type. The finding that protecting CfD plants from additional price risk through use of a local reference price only reduces both consumer & system benefits by C.£1.5bn over 2030-2050 further reinforces this point.
- 3.229 The analysis has also helped to confirm widely accepted learnings around the relationship between congestion and system benefits, with modelling indicating that the benefits of moving to locational pricing increase under a more constrained network. Over 2030-2040, the benefits of moving to locational pricing are 26% higher with a 3-year network delay.
- 3.230 Finally, the modelling has also made clear the importance of operational benefits. Alternative options to locational pricing currently have limited potential to send a locational operational signal meaning they are unlikely to significantly influence the real-time operation of the electricity market. Therefore, while some of these alternative options may be less transformative than locational pricing, the potential benefits for consumers are likely to be more limited.
- 3.231 A fuller explanation of the modelling approach taken and discussion around modelling results is contained in the full report.

## Distribution of Consumer Benefits

- 3.232 The overall consumer benefit figures presented above can also be decomposed by demand in each zone to give an early indication of possible regional differences. Figure 24 below illustrates the potential regional impacts from zonal pricing and is based on the year 2035 as it is the current target year for electricity system decarbonisation (subject to security of supply). This year also enables a higher degree of confidence in core model inputs such as network build. The analysis captures all modelled sources of consumer benefit in addition to the wholesale price impacts, to better understand the potential final result on end consumers. It does not represent a full assessment of regional impacts on end consumers, it is intended as indicative only, and does not presuppose future policy decisions. A more complete assessment of regional impacts will be progressed as part of the next phase of REMA.
- 3.233 The degree of variation between regions is highly dependent on policy design. Choices on the number of zones or distribution of congestion rents will greatly affect the distribution of any potential savings. The map below is based on modelling to illustrate potential benefits and does not represent a DESNZ view on the number or location of

zones. Zone boundaries will ultimately be based around the most significant network constraints.

- 3.234 Our assessment would expect general trends to be consistent across all consumer benefit scenarios. The analysis is necessarily highly stylised and the same limitations from the modelling above apply, such as the assumption that there is no change in the cost of capital. If consumers were exposed to locational pricing, then this could add additional system benefits from demand-side response, which were not included in the modelling described above. We are continuing to consider the impacts which zonal pricing would have on the retail market, including whether consumers could and should be partially or fully shielded from price differences.
- 3.235 The fundamental insight from this analysis is that zonal pricing has the potential to lead to savings for the typical household in all regions. Businesses are likely to experience a similar pattern of price reductions, with the impact for all consumers varying based on when and how much energy they consume. The benefits for individual consumers will also depend on how they choose to contract with their own supplier. Impacts are also subject to change over time, reflecting the supply and demand dynamics and network capacity of the grid. We intend to take consideration of the impacts on both domestic and non-domestic/industrial consumers in next phase of REMA.
- 3.236 As an indication of orders of magnitude, Figure 24 illustrates that if congestion rents are fully passed through to consumers and split evenly by demand, then we would expect households in the south of England and Wales to benefit by around £10pa, those in the north of England to benefit by around £50pa and those in Scotland to benefit by around £100pa in 2035. These differentials may change over time as the system responds to new price signals (e.g. generation and demand alter siting decisions, or new network is built beyond what is currently planned).

Figure 24: Potential Order of Magnitude - Regional Divergence in Consumer Benefits (annual) – 2035



- 3.237 As this diagram shows, in this scenario all consumers are better off but some consumers benefit by a greater amount. The price differentials described above (e.g. in the range of £0 £140pa) are of similar magnitude to the existing differences in typical household electricity bills, which are the result of regional network charging differences and losses (currently <£100pa). For example, in the January 2024-March 2024 Default Tariff Cap, the electricity component of the typical household bill for those paying by direct debit will range between £941pa (East Midlands) and £1025pa (North Wales & Mersey).
- 3.238 It is currently uncertain whether these two causes of regional price differences would have a compounding (leading to greater regional differences when combined) or offsetting (leading to smaller regional differences when combined) effect. This is because the future trajectory of network charging, which is a matter for Ofgem, is highly uncertain and itself dependent on wholesale market design, and because the design parameters of a zonal market are still to be decided. There are fundamentally different drivers underlying wholesale prices, which reflect the balance of supply/demand of electricity, and network charges, which reflect the cost of the electricity network.

Table 19: Regional breakdown of the current Default Tariff Cap period (January - March2024), using Typical Domestic Consumption Values<sup>38</sup> and including VAT. Figures are forelectricity (single-rate metering arrangement) of a typical household paying by Direct Debit.

Region (including VAT)	Average Electricity Component of Typical Household Annual Bill (including standing charge)	Ranking (most to least expensive)
N Wales and Mersey	£1025	1
Southern Scotland	£987	2
Northern Scotland	£986	3
Southern Western	£982	4
South Wales	£973	5
South East	£967	6
Northern	£960	7
Southern	£960	8
Midlands	£958	9
North West	£957	10
Yorkshire	£955	11
Eastern	£949	12
London	£943	13
East Midlands	£941	14

3.239 The logic map below (Figure 25) sets out some of the potential benefits and disbenefits pathways associated with any form of zonal pricing regime, focusing on those pathways not quantified in the above modelling. Our assessment sees these pathways as coherent with all forms of zonal pricing but notes the scale of these pathways would vary depending on the design decisions taken.

<sup>&</sup>lt;sup>38</sup> Figures based on Ofgem's typical domestic consumption value for electricity of 2.7MWh p.a.



#### Logic Map & Causal Chains



Reduced whole-system costs: reduced network & generation buildout costs



3.240 More reflective wholesale prices and more responsive siting by market participants reduces the need for network buildout. This is because wholesale prices make areas in need of reinforcement more visible, and more responsive siting reduces the need for buildout in unconstrained areas. This same line of reasoning also applies to generation costs; better operation and siting of new generation assets reduces the amount of generation build required and leads to a smaller system overall.

#### Decarbonisation: demand-side exposure



3.241 If consumers have locational signals passed through to them through zonal retail prices, consumers will be incentivised to take actions based on the local state of the network to reduce or shift their demand (e.g. through smart charging, rooftop solar, heat pumps and other smart solutions). This increases demand-side flexibility in a

<sup>&</sup>lt;sup>39</sup> Note that red connections denote inhibiting effects.

locationally conscious way and contributes to wider system decarbonisation. The extent to which consumers are exposed to locational prices is a policy choice, and some locational markets shield consumers entirely.

#### Disbenefit: increased whole-system costs: cost of capital



3.242 Under zonal pricing, generators would lose firm transmission access rights across zones. This would increase revenue uncertainty. Wholesale prices in each zone may also be more volatile as they are more granular and more reflective of physical changes; zonal prices may also be susceptible to change based on additional generation build, changes in demand and network buildout. This volatility could increase the cost of capital – however, increases could be mitigated against by various hedging mechanisms (e.g. FTRs or EPADs) and how Legacy Arrangements are treated.

## **Nodal pricing**

- 3.243 Nodal pricing is an electricity market design where the price in each location in the transmission network (also known as a "node") represents the locational value of energy. With nodal pricing, the physical constraints of the network capacity and losses are reflected in the market clearing process, with the associated costs fed through to the wholesale price.
- 3.244 Our assessment has considered modelling results on balance with stakeholder feedback and wider arguments across the earlier referenced assessment criteria. Our assessment is discounting nodal pricing from further consideration. This decision was taken on the grounds of deliverability and investor confidence.
- 3.245 For power assets, a key factor in determining the cost of capital is revenue certainty (which in turn will be driven by 1) volume certainty and 2) price predictability). While an asset's exposure to risk will vary greatly depending on the final policy design and individual asset characteristics, our assessment considers nodal pricing as more likely to lead to a greater increase in the cost of capital (both enduring and transitory).
- 3.246 Zonal pricing presents less risks to investors, in part because a greater level of volume certainty is retained. Nodal pricing, therefore, has the potential to lead to higher increases to costs of capital which could offset system savings from greater operational efficiency and disrupt our transition to 2035.
- 3.247 In addition to those concerns around investor confidence, our assessment views nodal pricing as extremely challenging to implement. Based on international precedents, we estimate zonal pricing could take at least 5 years to implement, and that nodal pricing (which would require central dispatch) could take up to a decade. There are also a wide range of precedents for aspects of zonal pricing in our current (or recent) market arrangements which should ease implementation and help reduce market uncertainty during any potential transition. Design choices to help minimise risk in a zonal design are discussed in Challenge 4 and Appendix 4 of the REMA consultation.
- 3.248 Finally, stakeholders' sentiment whilst generally against continuing to consider both nodal and zonal market designs was more heavily against nodal pricing. Discounting

nodal pricing but continuing to consider zonal pricing was seen as preferable to continuing to examine both or only nodal pricing.

## Locational Pricing Decision

- 3.249 Based on the above and the REMA case for change, there remains a strong case for locational pricing to help a) deliver a least cost electricity system and b) pass system savings onto end users.
- 3.250 Numerous modelling exercises have been conducted which demonstrate the possible system benefits of locational pricing. Studies conducted by FTI & Aurora both concluded that there are significant potential benefits from locational pricing, especially for consumers. However, the magnitude of these can vary depending on scenario and policy choices. Our assessment acknowledges that there is a strong case to continue to assess locational pricing due to the redistribution of surplus and the benefits of locational operational signals benefits which our alternatives to locational pricing cannot deliver.
- 3.251 Our assessment sees zonal pricing as both more deliverable and less likely to negatively impact the cost of capital of generators when compared to nodal pricing, whilst still having significant potential to deliver both system and consumer benefits through providing a more granular locational signal. Additionally, there is also a wide range of precedents for aspects of zonal pricing in our current (or recent) market arrangements which should generally ease implementation. Based on international precedent we estimate zonal pricing would take at least 5 years to implement. The importance of minimising complexity and implementation timeframes was expanded on above when longlisting nodal pricing.
- 3.252 Considering all of the above, which includes formal modelling, literature, and stakeholder feedback, we have reached the overall conclusion that there remains a strong case to continue to assess zonal pricing. The primary reasons for this are zonal pricing's ability to redistribute benefits to consumers and the benefits of locational operational signals benefits which alternative options to locational pricing cannot deliver. Further work will be needed to explore the exact scale of benefits, as well as interactions with other REMA policies such as mass low carbon support schemes. These schemes and wider policy design decisions have the potential to help protect producers from some downside risks while still maintaining the upside potential of more efficient locational signals.

## International Precedent for Locational Pricing

- 3.253 Following the first REMA consultation, we have examined a range of different countries' wholesale market arrangements informed by work conducted by Arup<sup>40</sup>. This is included in the supporting documents to this consultation, and we have also provided a brief summary of some of the key points below.
- 3.254 Arup focused on a range of market arrangements currently in place internationally, how these arrangements compare to current Great Britain (GB) arrangements, and the expected characteristics of the GB electricity system in the future. A summary of their findings is set out in section 4 of the report and covers the following areas: US markets (including CAISO, PJM, ERCOT, ISO-NE), zonal Nordic markets (Norway, Denmark,

<sup>&</sup>lt;sup>40</sup> Evidence from International Markets, Arup, 2024

Sweden), I-SEM, Germany, Belgium, Poland, Italy, and Australia (NEM). The table included below sets out a range of different parameters for comparison with the GB market which include dispatch regime, settlement period length, pricing rules and pricing design.

3.255 However, the applicability of these learnings to the GB context varies and are ultimately not directly generalisable. For example, dispatch arrangements vary significantly across even those markets which operate under zonal pricing (nodal markets in the US only operate under central dispatch). Even when a market is more comparable in overall size, such as CAISO, divergences can be observed in other key areas such as liquidity. This means whilst the overall rationale for such transitions may be consistent across markets, (the introduction of locational pricing is often driven by markets seeing increasing constraint costs and growing levels of re-dispatch) learnings cannot be easily applied in a GB context.

## Table 20: Summary of International Electricity Market Designs

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Market Characteristic	GB	US Markets (CAISO, PJM, ERCOT, ISO-NE)	Zonal Nordic countries (Norway, Denmark, Sweden)	I-SEM	Germany	Belgium	Poland	Italy	Australia (NEM)
Dispatch regime	Self-dispatch	All central dispatch	Self-dispatch	Central dispatch	Self-dispatch	Self-dispatch	Central dispatch	Central dispatch	Central dispatch
Settlement period (IDM)	30-minute settlement	All central 5 mins	60-minute settlement	30-minute settlement (IDM)	15-minute settlement	15-minute settlement	60-minute settlement	60-minute settlement	5-minute settlement
Pricing rules	Marginal unit sets the price	All LMP	Marginal unit sets market price	Algorithm sets market price	Marginal unit sets market price	Marginal unit sets market price	Marginal unit sets market price	Marginal unit sets market price	Marginal unit sets market price
Pricing design	Uniform	All Nodal	All Zonal	Uniform	Uniform	Uniform	Uniform	Zonal	Zonal
Total demand	294 TWh	CAISO: 211TWh PJM: 806.5TWh ERCOT: 481.8TWh ISO-NE: 118.7TWh	139 TWh	30.3 TWh	504.5 TWh	21.6 TWh	174.6 TWh	289.3 TWh	189 TWh
Peak demand	59 GW	CAISO: 43.9GW PJM: 149GW ERCOT: N/A ISO-NE: 25.8GW	Norway: 25.2GW Denmark: 6.4GW Sweden: 25.7GW	5.4 GW	81.4 GW	13.6 GW	27.4 GW	49.6 GW	32.8 GW
Electricity network decarbonisation target	October 2021, UK targets net zero power by 2035 and 2050 for the whole economy	CAISO target 50% renewable energy to retail load by 2030. PJM, ERCOT & ISO- NE all have no target	Norway: reduce GHG by 90-95% by 2050 Denmark: 100% renewable power by 2035. 100% renewable consumption by 2050. Sweden: 100% renewables by 2050	In 2019, Eirgrid targeted increases electricity production to 80% from renewables by 2030	January 2020, Germany targeted to decarbonise its electricity sector by 2035	Belgium supports EU carbon neutrality target by 2050.	February 2020, Poland agreed the PEP2040 which targets 32% renewable energy in the power sector by 2040	May 2021: Italy aims to increase renewables' share of electricity to 72% by 2030 and to 100% by 2050.	September 2022, Australia set a target to reach 82% renewable energy by 2030 and net zero by 2050.
Carbon Pricing	UK ETS + The Carbon Price Floor (CPF)	CAISO: California cap and trade, PJM & ISO-NE: RGGI ERCOT: no info	EU ETS Sweden carbon tax	UK ETS EU ETS Ireland carbon tax	Germany ETS EU ETS	EU ETS	EU ETS Poland carbon tax	EU ETS	Australia Carbon Exchange
Degree of interconnection (%)	6%	CAISO: no info PJM: no info ISO-NE: no info ERCOT: no info	Norway: 14.2% Denmark : 33.3% Sweden : 22.1%	3.9%	9%	14.3%	21.4%	2.3%	0%
Degree of intermittency (%)	28%	CAISO : 25% PJM : 4% ISO-NE : 7% ERCOT : 29%	Norway: 6% Denmark: 61% Sweden : 17%	36%	31%	20%	1%	15%	8%
Liquidity (Churn factor, forward markets)	2.5	PJM: 2.88 No info for CAISO, ERCOT & ISO-NE	Nordic: 2.5	0.5	8.5	<0.5	1.5	2	7

A notable point of difference is the extent to which international markets operating locational pricing vary in how they expose retail load/consumers to locational prices. For example, under nodal pricing some models operate minimal intervention approaches (e.g. ERCOT); under others, consumers pay the weighted average of the nodal prices in the region (PJM, CAISO), and others use nodal dispatch but zonal settlement (Ontario). Any potential GB zonal model will need to carefully consider the potential benefits and risks to consumers, and how these are passed on through differing levels of exposure.

- The markets assessed by Arup also varied significantly in their generation mixes (see below). The generation mix has been simplified into four categories: renewable energy sources (intermittent and non-intermittent) and dispatchable energy sources (low and high carbon intensity), with SEM the closest comparison with the GB market.
- However, no international market is a perfect comparator for the GB system. In the next phase of assessment, we will need to develop a fuller understanding of what a GB zonal pricing model could look like in practice, including potential salient interactions with the retail market, and do further work to assess its potential costs and benefits.



## Table 21: Summary of Generation Mix – International Electricity Markets

## Locational CM

- 3.256 A locational CM in theory could incentivise new build generation assets securing CM agreements to be located in less constrained areas of the transmission network. This would mean capacity secured through the CM locates more optimally from a system cost perspective and minimise the extent to which the CM adds to future constraint costs and/or the need for greater transmission investment.
- 3.257 The main credible options which have been identified to deliver a locational CM are:
  - Auctions for multiple zones Separate auctions for different zones, with different prices for the different zones.
  - Multipliers in bids The auction price would initially clear as one, but then multipliers to the price could be added afterwards to reward location and provide stronger investment signals to build where the capacity is needed.
  - Adjusting derating factors Derating factors could be adjusted by considering expected network congestion.
- 3.258 The assessment has looked at evidence from CM auctions and model output data, as well as international examples and academic literature, to gather evidence on the benefits and risks of a locational CM if it were to be implemented in Great Britian.
- 3.259 Analysis of data from capacity auctions shows the majority (>80%) of capacity secured through the CM is from existing capacity and existing interconnectors. This indicates

that the CM, due to the strength of the signal it sends, has limited ability to incentivise new capacity to locate more optimally.

3.260 Data from the recent T-4 for 2026 CM auction, as indicated by Figure 26, also shows the majority of de-rated capacity recently secured has been gas while only a small proportion came from renewable sources such as wind which is more likely to site at the extremities of the grid and exacerbate constraint issues<sup>41</sup>.

## Figure 26: Breakdown of Fuel Type for De-rated Capacity Secured in the T-4 2026 Auction



De-rated capacity procured at T-4 2026 by fuel type (in GW)

- 3.261 Analysis of the Dynamic Dispatch model's most recent Net Zero High scenario data (excluding batteries, pumped storage and interconnectors)<sup>42</sup> was used to investigate the potential significance of CM income for generators in the future. The Net Zero High scenario data shows an illustrative, net zero-consistent electricity demand and generation scenario for Great Britain, however it is not a forecast.
- 3.262 The key finding from analysis of this data was that the majority of generation is expected to come from assets which take no CM income payments, particularly as CfDs make up a greater proportion of generation, whilst assets that receive CM payments are modelled to contribute less to overall generation. This indicates that although CM payments may be an increasingly important payment for some generators, those generators are less likely to generate (but would likely be highly important in times of system stress), indicating that interventions in the CM have limited ability to alleviate constraints.
- 3.263 Although views from stakeholders have been mixed, most have been in opposition to a locational CM. Concerns were raised around implementation and increasing

<sup>&</sup>lt;sup>41</sup>Low renewable generator presence in the CM is likely due to renewables preference for CfD payments (Making them illegible for CM payments) & high derating factors.

<sup>&</sup>lt;sup>42</sup> Batteries, pumped storage and interconnectors are modelled as both producers and consumer of electricity. Data output is given as net of both production and consumption and cannot be easily disentangled. As such they have been excluded from this analysis.

complexity of the CM during a period when rapid investment is needed to hit net zero. Stakeholders did however highlight that a locational CM could be necessary as a supplementary option alongside other changes such as locational pricing.

3.264 Overall, the evidence examined suggests a locational capacity market would likely have limited ability to alleviate future constraints. We have therefore decided not to pursue a locational CM as a standalone measure to alleviate constraints.

## **Options (Non-locational)**

#### Table 22: Non-locational options

#	Option name	Assessment style
D	Temporal signals: Shorter settlement periods (15min/5min)	Short-list
E	Temporal signals: Shortening gate closure	Long-list: failed assessment criteria on Deliverability
F	Improving balancing and ancillary services: BM reform	Short-list
G	Improving balancing and ancillary services: Central dispatch	Short-list
Η	Improving balancing and ancillary services: Additional measures to maintain operability in a decarbonised electricity system cost effectively (see annex)	Short-list
1	Improving local and national co-ordination: Local wholesale markets	Long-list: failed assessment criteria on Deliverability

## Temporal signals – Shortlisted: Shorter settlement periods

- 3.265 Shortening the imbalance settlement period (ISP) duration (e.g., to 5 or 15 minutes) would create a more 'granular' wholesale market temporal signal. This could potentially lead to greater market participation by smaller and innovative flexible and demand-side response assets and reduce overall costs by moving volumes out of the Balancing Mechanism and into the wholesale market.
- 3.266 The costs of implementing a change to the settlement period duration are likely to be significant, with impacts for trading platforms, metering and notification systems, scheduling and settlement, billing systems and more.
- 3.267 There are grounds for continuing to consider this option as part of REMA. Market conditions have changed significantly since Ofgem's 2020 assessment of shorter settlement periods, which was carried out through a narrower lens, as it did not consider interactions with other REMA options.
- 3.268 Following the first REMA consultation, Arup conducted a study on the potential wholesale market reforms, including the implementation of shorter settlement periods. Arup concluded that a transition to a 5-minute settlement period would likely deliver higher benefits versus a 30-minute or a 15-minute period and would likely be better suited to future GB electricity market with greater flexibility requirements. However, this study did not represent a comprehensive CBA.

3.269 Any decision to shorten ISPs will require a careful consideration of the likely costs and benefits. These costs and benefits may vary significantly depending on any wider package of reform. For example, the value of a 5 or 15-minute ISP duration could be different when combined with centralised dispatch and/or zonal pricing.

## Figure 27: Shorter settlement periods – logic map

## Shorter settlement periods



## Reduced whole-system costs: reduced balancing costs



3.270 Shorter settlement periods increase the temporal granularity of wholesale markets. This means that market participants are more incentivised to match supply and demand in shorter timeframes, as instead of needing to be in balance over 30 minutes (which allows e.g. peaks and troughs) they would need to be in balance every 15 or 5 minutes and are therefore more accountable for imbalance. This increases the amount of trading at intraday stage and consequently means that volumes are moved from the Balancing Mechanism to the intraday market. This reduces balancing costs.

## Reduced whole-system costs: greater intraday market liquidity



3.271 The increased temporal granularity also creates more accurate price signals in wholesale markets, which smaller flexibility and demand response providers may take advantage of. This means that a greater number of market participants can access the

intraday market, and results in increased trading activity at the intraday stage. Intraday market liquidity is therefore increased overall relative to the status quo.

## Temporal signals – Longlisted – Shortening gate closure

- 3.272 We have also been considering the idea of tighter gate closure. One barrier to temporal flexibility is arguably the 60-minute Gate Closure interval. Gate Closure is the point at which most trading ends and the BM begins. Participants submit Final Physical Notifications (FPNs) signalling their expected physical positions. The fact that market participants should stick to the positions indicated in FPNs denies them the opportunity to make adjustments closer to real-time, on the basis of the latest information.
- 3.273 Arup's study on wholesale Arup's study on wholesale market reforms concluded that as the technology and generation mix advances, a 30-min gate closure interval should be considered further through a Cost Benefit Analysis, but that anything below that could lead to adverse impacts when it comes to system costs and security of supply. Arup identified various benefits related to shorter gate closure, including better management of uncertainty around matching supply and demand, enhanced investment/ market participation incentives for fast response flexible assets, and incentivisation of Demand Response participation.
- 3.274 However, Arup identified a few drawbacks. For example, if gate closure is shortened too much it could lead to an increase in balancing costs by limiting the options available to the SO. The current generation mix's response time poses limitations on how close gate closure can be brought to real-time; the ESO suggested that most CCGTs have ramp up rates between 60-89mins.
- 3.275 Our view is that tighter Gate Closure is not something that could be implemented in the short- to medium-term but could form part of a long-term market design (2030 and beyond). We are therefore discounting it as part of the REMA package of reform.

# Improving balancing and ancillary services – Shortlisted - Balancing mechanism reform

- 3.276 The Balancing Mechanism (BM) is the ESO's primary tool to balance supply and demand and maintain reliability. The ESO uses the BM to correct the market outcome via 'redispatch': buying and selling electricity in real time and instructing certain parties to adjust generation and/or consumption. Participation is mandatory for larger parties and optional for smaller parties. We are keen that future BM reforms target the following two priorities:
  - Competition A future BM should be competitive, such that costs are reflective of the underlying cost of providing a service and it should be designed in a way that ensures it is accessible to a wide range of participants
  - Transparency In consideration of the BM's shortcomings as a market that is procuring a variety of services at once with limited competition, the ESO should prioritise providing suitable levels of transparency, so as to enable greater participation and widen access to low carbon and demand side participants.
- 3.277 In addition to the two priority areas mentioned above, we believe further work is necessary across all markets to address baselining methods for DSR, standardisation and simplification where possible to improve revenue stacking, lowering participation

thresholds and introducing closer to real time procurement. In Appendix 3 to the 2024 REMA consultation, we have provided a more detailed description of each of these and, if applicable, a summary of the work already underway which might help to address them.

- 3.278 BM reform may also be necessary in the context of the wider challenges described above. For example, the BM currently plays a very important role when it comes to constraint management and should therefore be considered in the context of discussions around both locational pricing and alternatives to locational pricing.
- 3.279 Arup considered potential aspects of BM reform as part of their study on reforms to the wholesale market. They concluded that applying a cap on BM offer prices could be complex when it comes to finding the right balance of setting the cap at the right level whilst not hampering investment signals. Changing the cash out mechanism, in Arup's view, could have adverse market effects as it reduces the incentive of market participants to balance their position ahead of real-time. The introduction of locational products in the BM bears the risk of generating market power for participants located in regions or areas where services are required. Arup's view on the preferred option was to proceed with an enhanced version of Ofgem's proposal to cap BM generator margins if they submit a Physical Notification between zero and their Stable Export Limit (SEL).

## Improving balancing and ancillary services – Shortlisted - Central dispatch

- 3.280 The first consultation raised whether the current self-dispatch arrangements (encompassing residual balancing via the BM) remain appropriate, or whether a move to centralised dispatch would be beneficial.
- 3.281 In this context, dispatch refers to two activities:
  - Determining and refining the operational schedule.
  - o Issuing real-time dispatch instructions to generators.
- 3.282 The ESO are currently assessing the case for reform to GB's dispatch arrangements, with projects comparing how market parties schedule under self and central dispatch and quantifying the economic benefits of co-optimisation. ESO will be publishing results in Spring 2024. Any transition to centralised dispatch would likely then entail significant implementation costs, challenges, and risks for market participants. The benefits would therefore need to outweigh these risks, and any potential implementation would need to minimise market disruption.
- 3.283 Arup's study on wholesale market reforms did not identify international examples of transitioning from self to centralised dispatch. However, based on analysis of transitions of a similar scale, Arup's view is that GB would need at least 5 years to implement such a reform. According to Arup, NESO would need to bear most of the effort with IT and Documentation costs being the highest for most market actors, and it is unclear whether the costs of implementation would outweigh the benefits.

# Improving balancing and ancillary services – Shortlisted - Additional measures to maintain operability in a decarbonised electricity system cost effectively

3.284 See consultation document challenge 4 and annex. Further analysis will be carried out as options develop.
#### Improving local and national co-ordination – Longlisted - Local markets

- 3.285 In the previous consultation, we set out a local markets option, highlighting two theoretical models which aimed to reorient the wholesale market around local, distribution-level markets to more effectively utilise the distribution network and the increasing volumes of distributed generation and demand which will be available on the system.
- 3.286 However, we have decided to discount this option as there are significant uncertainties around the cost and benefits of this approach. This is compounded by the fundamental and widescale changes which would need to be made to market arrangements for national roll-out, as well as the lack of proven international precedents. However, we are continuing to explore how we can strengthen operational signals through the other options set out in this challenge to facilitate the deployment and utilisation of low carbon distributed flexibility. The analysis of this option has been supported primarily by externally commissioned research conducted by CEPA on Local Electricity Markets, which has been published alongside the consultation.

# Appendices

# Appendix A: Logic Mapping

This annex sets out our approach to a programme of logic mapping work which supports this Options Assessment. Logic maps set out how an intervention delivers a series of results that contribute to delivering its final intended impacts – i.e. they provide an overview of the "causal logic" that underpins an intervention, and act as a precursor to full theories of change.

In a REMA context, articulating these causal chains, and understanding where they are comparatively stronger and weaker, provides a consistent framework for our evidence base and a structured way of communicating the benefits cases of different options across the REMA programme.

The maps will also inform future monitoring and evaluation activity and help to surface key performance indicators/metrics for any reform(s) (e.g. causal chains could form the basis of contribution claims/process tracing hypotheses dependent on the chosen impact evaluation approach).

Mapping took place through a series of interactive workshops held with REMA policy and analytical officials. Note that discounted options were considered out of scope for the purposes of this phase of mapping.

The logic maps are not intended as an exhaustive – or systemic - representation of all potential impacts or delivery considerations, and given their hypothetical nature there is an inherent element of subjectivity involved. The exercise was also constrained to an extent by the lack of a detailed implementation pathway for some options - where design considerations materially affect outputs, outcomes, or impacts, this is noted in square brackets, but it is reasonable to expect that new impacts will materialise in places as policy design develops.

# Appendix B: System Mapping

This annex describes our approach to a programme of system mapping work that supports the Options Assessment. System mapping is a technique used to visually interpret a given system, and specifically focuses on articulating the causal relationships between different system components.

The REMA system map sets out the key markets and policy interventions currently in place, and future policy options we are considering in this Options Assessment. Nodes of the map represent aspects of market arrangements that are most helpful to communicate the map succinctly, and as such some relationships are combined where there is no substantive impact on the overall system.

Map connections were developed through qualitative analysis of stakeholder views on current and future policy options from the initial REMA consultation, using a matrix exercise to highlight connections between policy options that may not have surfaced initially. For example, stakeholder responses discussing 'flexibility' in non-flexibility specific consultation questions were then analysed in an "X affects Y" format.

Connections were allocated as either "increasing" or "decreasing" directive relationship between system nodes. Specifically, "increasing" connections refer to either a direct or indirect reinforcing channel, and "decreasing" connections refer to either a direct or indirect opposing channel. For example, the section below shows that intermittent volumes below the clearing price in the Capacity Market affects and reinforces merchant intermittent assets' profit (in unconstrained areas).



After initial connections were identified via qualitative analysis, maps were developed in further workshops held with REMA policy and analytical officials.

3.287 The systems map is not intended as an exhaustive representation of the electricity system, but rather seeks to reflect key market mechanisms and policy options in scope of the REMA programme.

The basic structure of the map is as follows:

- Top quadrant: wholesale market arrangements and support mechanisms
- Left quadrant: system under constraints
- Right quadrant: system without constraints
- Bottom quadrant: network charging elements, and retail markets

**Review of Electricity Market Arrangements - System Map** 



# Appendix C: Monetary flows map

This section details a high-level illustrative map of some of the key monetary flows through the energy market for 2021. Data has been compiled from a range of sources and is a highly simplified view of the electricity market. This analysis:

- Assumes each segment of the energy bill has only one main final recipient (all segments detailed below)
- Excludes most intermediary organisations which may take some portion of financial flows through the system. Those including financial institutions, co-ordinating bodies and monetary collection bodies (other than suppliers and the LCCC).
- Excludes many of the smaller financial flows some of which are detailed in the assumptions section.

#### Methodology

2021 was chosen as the most recent full year which was not significantly distorted by the sharp increase in wholesale gas prices and the Energy Price Guarantee. This is intended to be more representative of a more typical year of monetary flows in the energy market.

Recipient/sources of money in the map are grouped into stakeholder groups for simplicity, however it should be noted that for example some suppliers are also generators and other stakeholders may be categorised into more than one stakeholder group.

Many of the smaller financial flows have been excluded from this graphic, particularly those to most intermediary organisations which often deal with the handling/co-ordination of money transfers. These payments are incorporated within the flow to the main recipient stakeholder group. This means many flows may be an overestimate of the total money received by recipients.

Financial institutions also play a part in the trading of energy products; however, this was also out of scope of this analysis.

Rents that accrue to generators (the excess above their short run marginal costs) is determined by the total wholesale market cost of the marginal plant (assumed to be composed of wholesale electricity costs, UK Emissions Trading Scheme costs, Carbon Price Floor costs and some network costs). This simplified illustration assumes all rents are recorded in the wholesale electricity costs component.

Some segments of the energy bill are two directional e.g. CfDs - the net flow is what has been illustrated in the map.

Key	finar	ncial	flows
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Flow	Segment	Final recipient	Source	
Wholesale ma	Wholesale market costs			
Wholesale Market costs	Wholesale electricity costs	Generators	Based on published data for production costs minus non- wholesale market costs	
	UK Emissions Trading Scheme	Government	Based on estimates of the average annual secondary market price multiplied by recorded surrenders for the year.	
	Carbon Price Support	Government	From public data	
Network costs	6			
	Transmission	Network operators and owners	Based on TNUoS public data	
Network costs	Distribution	Network operators and owners	Based on estimates of overall contribution of distribution charges to total energy bill	
	Balancing	Network operators and owners	Based on BSUoS public data	
	Connection charging	Network operators and owners	Based on data provided by the ESO	
Infrastructure	Infrastructure, social costs, and taxes			
Renewable Obligation	Renewable Obligation	Generators	Based on published data	
Feed-in- tariffs	Feed-in-tariffs	Generators	Based on published data	
CFD	Contracts for Difference	Generators	Based on published data	
СМ	Capacity Market	Generators	Based on published data	
CCL	Climate Change Levy	Government	Based on published data	

Value Added VAT Tax	Government	Based on published figures
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#### Other assumptions:

- 1. Financial flows have been rounded to the nearest £100m.
- 2. It should be noted that the data sources used for the above graphic have varying levels of uncertainty and that it is only for illustrative purposes. Network costs are particularly uncertain in the above for a variety of reasons. It should also be noted that losses through Distribution and Transmission are uncertain, but it is assumed those losses are included with the Network cost values.
- 3. Data for some flows was not available for the specific calendar year. Where that has been the case, a close alternative has been used instead.
- 4. For many flows the money collected from consumers may not be paid to the final recipient in the same year and/or the amount received may be slightly different. This can be due to hedging, trading, administration, payments to intermediary organisations or other reasons. Where data was unavailable it has been assumed that the amount consumers pay, and recipients received is the same and that payment is made within the same year.
- 5. Inflows may also not fully match outflows as a result of rounding.
- 6. For simplicity the cost of mutualisation for the RO has not been included
- 7. Money for Balancing is assumed to be equally split between suppliers and generators before being passed on to the National Grid.
- 8. It should be noted that although some segments of bills are depicted as coming from 'a stakeholder group' these are not necessarily equally shared. Many bills will only come from a subsection of that group for example in the instance of VAT and the CCL.
- 9. Similarly for recipients it should not be assumed that money is equally shared by recipients.
- 10. Money from various segments of the energy market is used to fund bodies such as Ofgem, Elexon and other cross industry regulators / service providers. Although not shown in the above graphic, they are reflected in the values of flows to the recipients that fund them.
- 11. Financial flows under £100m were not included within this map.
- 12. There may be some flows beyond those represented, e.g. flows from Government to consumers, however these are out of scope of this analysis.

# Appendix D: Counterfactual scenario analysis

#### Modelling approach

Counterfactual scenario analysis was designed to illustrate the potential impacts of REMA on the wholesale electricity market by comparing a non-REMA counterfactual to a highly stylised REMA scenario. It is a tool to illustrate potential orders of magnitude and is not a reflection of Government policy or any preference therein. The starting point for the analysis is the current Net Zero scenarios (published in Annex O of the Energy and Emissions Projections (EEP 2021): https://www.gov.uk/government/publications/energy-and-emissions-projections-2021-to-2040) which were developed using the Department's Dynamic Dispatch Model (DDM).

#### **REMA** Counterfactual

The REMA counterfactual takes the Net Zero higher demand scenario and makes a number of amendments to show how a sub-optimal system could evolve if the current market arrangements are maintained. The scenario described here represents just one (simplified) possible state of the world without REMA in order to illustrate the magnitude of the potential benefits and is not a forecast, or statement, of Government policy.

The counterfactual was constructed under the assumption that necessary action would be taken by the system operator to maintain security of supply, but that emissions ambitions might not be met. The social cost of additional carbon is included in modelled system cost estimates. One alternative approach could be to assume that emissions ambitions are still met but at much higher cost both for construction and financing and due to increased locational balancing actions. Our overall approach leans towards making conservative assumptions with the implication being that there is significant upside potential from REMA reform not captured here. Key assumptions:

Inclusion of locational balancing – modelling the most important boundaries (those which are most likely to be constrained) between 12 GB zones as outlined by NGESO in their NOA7 refresh report (described in detail on p29-30 of the LCP Delta "System Benefits from Effective Locational Signals" report (insert link)).

The scenario assumes demand is split across the 12 zones in the same proportions as the LCP Delta core scenario, with the same assumed Transmission Network reinforcements based on NOA7 + Holistic Network Design (HND) (see p36-40). LCP Delta modelled the system with technology capacities fixed but with future plants able to choose the optimal location in which to build, with both national pricing and with zonal pricing, to assess the cost impacts.

Flexible low carbon deployment was reduced to minimal levels, with the default replacement being unabated gas, while renewable and nuclear build was assumed to be unchanged. For renewables this is a conservative assumption because current market arrangements may not deliver the required new build. If sufficient unabated gas capacity was not available then system stress events would occur, increasing system costs significantly as any unmet demand would be priced at the Value of Lost Load (VoLL).

Future plant locations were aligned with the LCP Delta national pricing run of their core scenario, resulting in less efficient dispatch due to greater network constraints, which need to be resolved through locational balancing, leading to a higher cost system when all else is equal (i.e. the capacity mix is the same).

Technology-specific hurdle rates are used to model financing costs for plants in the DDM (<u>see</u> <u>2018 Europe Economics report</u>). These are unchanged in the counterfactual, except for

new unabated gas assets for which they are increased by 100bp in the counterfactual to reflect the challenging regulatory and operating environment. Increases to financing costs for other technologies due to greater investment risk for developers would increase the counterfactual system costs further.

Interconnectors are assumed to be always available for balancing both for uncertainty due to demand/intermittent generation and to resolve network constraints. Interconnectors do not currently participate in the Balancing Mechanism and the system operator instead makes bespoke arrangements with individual interconnectors. In a system modelled with reduced flexible low carbon capacity, interconnectors play a greater role in balancing and so the observed benefits of REMA in this analysis may be understated.

#### **REMA Scenario**

- Final market design choices for REMA policy options are yet to be determined through the second phase of the programme, so the NZ higher demand scenario was taken as a proxy for a REMA scenario, where the final market design is assumed to deliver a system that achieves decarbonisation ambitions at low cost, through effective (both in scale and location relative to demand) deployment of low carbon and renewable capacity, along with sufficient flexible capacity to maintain security of supply.
- The stylised REMA scenario adds locational balancing to the NZ higher demand scenario but leaves the capacity mix unchanged and sites new build in line with the LCP Delta zonal pricing model run to reflect the potential benefits to the system of improved locational signals to developers (but it continues to model national prices). The emissions trajectory broadly matches the NZ higher demand scenario.

#### Results

- The REMA scenario has lower system costs than the counterfactual by around £35bn over 2030-2050 (£2023, discounted), though the use of conservative assumptions means there is significant upside potential. System costs include:
  - Capex (Construction + Financing)
  - Generation (Fixed/Variable Opex + Fuel)
  - Carbon (Social Cost)
  - Unserved Energy
  - Balancing
  - Networks
  - Interconnectors
- Around £5bn is due to higher financing costs for unabated gas plants in the counterfactual, with the remaining benefits split roughly equally between more optimal siting of new capacity and flexible low carbon replacing unabated gas. Emissions in the counterfactual are much higher, remaining at 8Mt in 2050, while the REMA scenario falls to 1Mt. As discussed, the potential implications of security of supply issues in the counterfactual are not captured in the £35bn and neither are the adverse effects of a more limited role for interconnectors in balancing which would increase costs more in the counterfactual.

The results presented here are intended to offer a potential order of magnitude of impacts. As REMA policy development and the accompanying analytical approach deepens, estimates of impacts of specific policies and overall market design will be refined offering a richer source of quantification, including consumer impacts.

# Appendix E: Stakeholder evidence and qualitative evidence collection

#### Approach to qualitative/stakeholder evidence

Our engagement activities have been structured to yield meaningful qualitative evidence. This section sets out our qualitative evidence base in further detail, with particular focus on:

- Responses to the first consultation,
- Insights from our three Market Participant Forums,
- Qualitative interviews to complement the above.

Whilst the below seeks to reflect the key points of feedback we have received; it is not intended to be exhaustive.

#### **Responses to the first consultation**

The first consultation received 225 responses from a range of electricity market participants and wider stakeholders. Of these, a significant number were received from generators and developers, but representative bodies, energy infrastructure, academia, suppliers, and private individuals were also represented. We analysed responses using a qualitative coding approach and published a summary of the feedback on 7 March 2023.

- On programme design and cross cutting issues, the majority of respondents agreed with our vision and objectives for electricity market arrangements, the challenges we identified, and our assessment that current market arrangements are not fit for purpose. Respondents also broadly agreed with the proposed options assessment criteria and with our organisation of options, though responses to our assessment of cross-cutting issues and trade-offs were more mixed. Respondents generally agreed that we were considering all credible options.
- On wholesale market reform, most respondents agreed that there was merit in continuing to consider incremental reforms to existing arrangements but were divided on the more transformative options under consideration (split markets/locational pricing).
- On mass low carbon power, most respondents favoured centralised, government-led options over decentralised alternatives.
- On flexibility, respondents agreed that stronger operational signals were necessary to better incentivise flexibility and there was reasonable support for introducing a revenue cap and floor and reforming the Capacity Market, though a majority were against introducing a supplier obligation.
- On capacity adequacy, a significant majority supported reforms to the Capacity Market and agreed with government's decision to discount decentralised alternatives, though saw merit in continuing to consider a strategic reserve and centralised reliability option.
- On operability, respondents supported enhancing existing policies and modifying the CfD scheme to better incentivise the provision of ancillary services.
- On options spanning multiple market elements, respondents did not support continuing to consider either the Dutch Subsidy scheme or an Equivalent Firm Power auction.

#### **Market Participant Forums**

The Market Participant Forums employed deliberative methodologies to facilitate and supplement discussions on key strategic and policy issues in the REMA programme. In total, we hosted three forums focussing on the following issues: (1) decoupling gas and electricity prices, (2) locational signals, and (3) mass low carbon power and flexibility.

#### MPF1 – Decoupling gas and electricity prices

- The first MPF focused on decoupling gas and electricity prices, in particular Contracts for Difference (CfDs) and Power Purchase Agreements (PPAs), a Green Power Pool (GPP), and a Split Market.
- Stakeholders generally agreed that a combination of CfDs and PPAs had already decoupled prices to some extent, and that this would continue in the future as the amount of gas generation reduces.
- Participants also considered the GPP using the journey map and felt the option would not improve on the status quo and would add unnecessary complexity and opportunities for gaming. Participants highlighted imbalance risk, the practicality of supplier obligations and the impact of multiple auctions on liquidity as key design issues.
- Split markets were seen as too complex and disruptive a measure with significant deliverability risks, and benefits likely to outweigh the risks. Participants highlighted price formation in the LRMC market as a particular issue.

#### MPF2 – Locational signals

- The second forum focused on locational signals in current and future electricity market arrangements, with sessions on the impact of more efficient locational signals, zonal and nodal pricing, and on non-wholesale-pricing locational options.
- Most participants felt that TNUoS charges provide a locational investment signal, but in practice are one of several factors that influence final siting decisions.
- Participants generally felt the risks associated with nodal and zonal pricing outweighed the benefits, though some saw merit in zonal pricing.
- On non-wholesale locational options, participants felt that constraint management markets were worth exploring further; views on other measures were more mixed.

#### MPF3 – Mass Low Carbon power and Flexibility

- The third forum explored barriers to low carbon and distributed flexibility, methods of maximising investment in flexibility and enabling competition between low carbon flexible technologies, and options of a revenue cap and floor and CfD reform.
- Participants felt that barriers to low carbon flex identified by DESNZ were 'quick wins' with low regrets compared to more fundamental options for market reform. Additional barriers identified included reforms to DUoS charges, low liquidity, and metering requirements.
- Participants saw merit in a revenue cap and floor and a deemed CfD but identified design issues such as the potential for gaming (cap and floor) and identifying a suitable

reference generator under the financial model, compatibility with co-location and calculating generation potential (deemed CfD).

#### Additional qualitative research

To complement the insights from our forums, we carried out nine qualitative interviews with industry participants. Questions focused on key issues for future market arrangements to address, locational signals, support for low carbon flexible capacity and what a cohesive set of future market arrangements might look like.

Most interviewees agreed with the challenges highlighted by the REMA programme, but few could identify a clear vision of coherent future market design.

Almost all interviewees saw merit in a strategic planning approach, arguing this would position GB as a stable market for investment, and increase market confidence around meeting 2035 Net Zero targets.

Few interviewees supported locational pricing, citing significant implementation challenges and associated costs or investment risks. However, interviewees did acknowledge weaknesses in current market arrangements that locational pricing could theoretically ease.

Interviewees were supportive of the CfD scheme and saw merit in a deemed CfD as an effective mitigation mechanism for price and volume risk, though all felt that further design clarity was needed.

Interviewees agreed that incentivising the full range of low carbon flexible technologies is necessary to deliver a decarbonised power system and highlighted barriers to deployment under current market arrangements. These included the complexity of accessing the Capacity Market for small-scale flexible technologies, and the need for specific support mechanisms for FOAK technologies and long-duration storage.

# Appendix F: Market liquidity considerations

Liquidity is a measure of the degree to which a product (such as electricity) can be quickly bought or sold without affecting its price and without incurring significant transaction costs. Liquidity supports competition in generation and supply, which has benefits for consumers in terms of downward pressure on bills, better services, and greater choice.

For the market to function properly, we need both short-term (intra-day and day ahead) and long-term markets (futures and forwards) to be liquid. Liquid short-term markets i.e. intra-day and day ahead, are important as they enable market players to fine tune their market positions and to contract for the physical delivery of electricity. Liquid forward markets are important as they enable market players to manage their financial risks, such as unexpected changes in electricity prices, through hedging. Short-term markets are typically traded through exchanges, and forward markets are typically traded bilaterally through brokers (also known as over the counter or OTC). The large majority of trades in the GB market are done OTC.

There are three different types of participants in the GB electricity wholesale market: generators and suppliers (known as physical traders) and intermediaries (known as nonphysical traders). Physical traders need to buy and sell electricity to match their demand / generation. Non-physical traders do not own either supply or generation and participate in the market solely to make a profit through arbitrage. Some physical traders also trade for profit, as well as buying and selling electricity to match their demand / generation. Non-physical traders improve market liquidity and are an important component of a healthy market, therefore we want to encourage their participation. As the electricity market regulator, Ofgem are responsible for ensuring that the GB wholesale electricity market, as it currently exists, is sufficiently liquid to provide efficient outcomes for consumers. The role of REMA is to ensure that liquidity is maintained under the transition to our future market arrangements, and that the market remains transparent and accessible to all participants.

#### Liquidity trends

In the early years following liberalisation in 2000/2001, liquidity in the GB wholesale market rose to reasonable levels. But by 2004, it had fallen back to a level that was low compared to some (but not all) other electricity markets internationally. It has stayed broadly at this level ever since, with some degree of fluctuation.

In recent years, liquidity has been falling further, particularly in forward markets. Market participants are concerned about this, as it makes it more challenging to manage their financial risks through hedging. Liquidity over all timeframes, but particularly in forward markets, fell sharply over winter 2022/23 to the lowest on record (partially due to high and volatile prices), but concerns have since recovered somewhat as prices have stabilised.

Going forward, we are likely to see liquidity in forward markets continuing to fall on a long-term basis (i.e. outside of acute market shocks). This is because of the rise of renewable generators on the system and the design of the CfD [will insert Ofgem data]. Electricity generation is becoming more weather dependent, which is introducing increasing amounts of risk into the market. The CfD is designed to remove this risk from renewables generators, in order to drive low-cost investment in renewables. It does this by providing them with a perfect hedge of price risk. Whilst this is effective in its goal of driving investment, it also removes incentives for renewables generators to participate in forward markets. Therefore, it reduces forward market liquidity as it reduces the number of generators participating in this segment of the market. But suppliers still need liquid forward markets in order to manage their risk through hedging. The

current default retail tariff price cap heavily incentivises suppliers to hedge through forward markets according to a prescribed methodology.

### **Ofgem interventions**

Since 2008 Ofgem have monitored the low levels of liquidity and considered options for improving it, including a targeted intervention between 2013 – 2019 (the S&P MMO), as well as various industry-led solutions aimed at encouraging non-physical trader participation, such as increasing the use of exchanges – as exchange trading is more transparent than OTC. The success of these measures has been limited.

Later this year Ofgem will be publishing a call for input to gather industry views on current power market liquidity trends, issues, and concerns and to explore the case for further market intervention to improve liquidity.

### **REMA** options which affect liquidity

We have reviewed which REMA options could affect liquidity. These are (in order of importance):

- Locational Pricing. A move to zonal pricing would fragment the market spatially. This could potentially reduce liquidity, particularly in forward markets due to the additional price uncertainty created, as well as the fragmentation of the market. However, mitigations exist notably virtual trading hubs and alternative hedging products such as financial transmission rights and have been applied effectively in other markets internationally. Even with mitigations in place, there is still a risk of negative impacts on liquidity during a transition to locational pricing, due to the radical change in market arrangements. Going forward we will consider liquidity impacts and mitigations in the design of our zonal option for locational pricing.
- CfD reform. This scheme, specifically the market reference price it contains, guides how renewables participate in forward markets. Reforming the CfD, by changing the reference price or moving to a model without a reference price, could therefore either reduce or increase liquidity in forward markets, depending on how it is designed. However, there are risks to reforming the CfD in this way to increase market liquidity, including introducing new basis risk for generators who want to sell their power closer to real-time and disadvantaging smaller assets who may not have the collateral to participate in forward trades. This increase in risk for generators could increase drive up strike prices, making the CfD the scheme more expensive for consumers. See section X in challenge 2 which discusses options for reforming the CfD reference price methodology in more detail.
- Central dispatch. This measure could reduce or increase liquidity, depending on the design of the measure. It could have a positive impact on liquidity in short-term markets, as transactions are pooled centrally. Although allowing self-commitment (which has other benefits) could result in liquidity being split and therefore reduced. As for locational pricing (which is often combined with central dispatch), central dispatch could lead to a drop in liquidity in forward markets. However, mitigations exist for this, notably alternative financial products for hedging, and many central dispatch models internationally have good liquidity. Even with mitigations in place, as with locational pricing there is still a risk of negative impacts on liquidity during a transition to central dispatch. Going forward we will consider liquidity impacts and mitigations in the design

of our zonal option for locational pricing and our central dispatch under national pricing option.

• Shorter settlement periods. This measure could increase liquidity in intra-day markets as it could unlock more participation from flexible technologies and allow more options for market participants to trade ahead of gate closure. We will consider these potential liquidity benefits in our assessment of these options.

# Appendix G: Glossary

Allocation Round (AR)	Now annual Contracts for Difference auctions which see a range of different renewable technologies competing directly against each other.
Balancing Mechanism (BM)	One of the tools the Electricity System Operator (ESO) uses to balance electricity supply and demand close to real time. Where the ESO predicts that there will be a discrepancy between the amount of electricity produced and the level of demand during a certain half-hour period, they may accept a 'bid' or 'offer' to either increase or decrease generation (or consumption).
Baseload	Plants that are running continuously over extended periods of time, for example large-scale nuclear power plants, are said to be baseload generators. The power from these plants is used to meet the minimum demand of the system.
Bespoke mechanisms	Specific policy support to bring forward investment for low carbon flex which is due to technology specific risks in unable to compete in the current Capacity Market (CM).
Bio Energy with Carbon Capture and Storage (BECCS)	Bioenergy generators (i.e. burning biomass to produce electricity) with carbon capture and storage.
British Electricity Trading and Transmission Arrangements (BETTA)	A set of arrangements which came into effect on 1 April 2005 to harmonise electricity trading across GB. BETTA is based on bilateral trading between generators, suppliers, customers and traders, and participants self-dispatch rather than being dispatched centrally by the Electricity System Operator.
Capacity adequacy	A term to describe whether the pool of generation assets is sufficient to meet electricity demand at any given moment amid any given set of circumstances.
Capacity Market (CM)	A mechanism to contract reliable sources of capacity, to ensure they respond when needed, to help support security of supply. This results in payment to any generator (or storage / demand side response provider) who can respond when notified upon by the Electricity System Operator (ESO) in times of system stress. Auctions for this capacity take place at both four years and one year ahead of delivery, and agreements generally last for one year.
Capacity mix	The mix of various energy sources and technologies for electricity generation.
Capex	Total capital expenditure for a project.

Carbon Budget Six (CB6)	Required under the Climate Change Act 2008, this places a restriction on the total amount of greenhouse gases the UK can emit during the period 2033-2037.
Carbon capture, usage and storage (CCUS)	A technology for capturing carbon dioxide that would otherwise be emitted from a process (e.g. electricity generation) and either using it (often in industrial processes) or permanently storing it.
Carbon price support	Electricity generated from fossil fuels is taxed to guarantee a minimum price for CO2 emissions.
Centralised reliability options	An option considered as an alternative to the Capacity Market, which obligates contract holders to pay the difference between the real time price and the agreed strike price when there is a system scarcity, and the real-time price is higher than the agreed strike price.
Colocation	Sometimes referred to as 'co-location' – is broadly defined as two technologies sharing the same utility-scale grid connection point, often within the same site. For example, battery storage located alongside an on-shore wind generating station.
Combined-cycle gas turbine (CCGT)	An electrical power plant technology in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency than would be possible independently.
Consumers	Those that consume electricity – including domestic consumers (e.g. households), and non-domestic consumers (e.g. businesses and industry).
Contract for Difference (CfD)	A 15-year private law contract between low carbon electricity generators and the Low Carbon Contracts Company (LCCC). Typically, contracts are awarded in a series of competitive auctions. Generators receive revenue from selling their electricity into the wholesale market. When the market reference price is below the strike price, generators receive a top-up payment for the additional amount. If the reference price is above the strike price, the generator must pay back the difference.
Day ahead market	A financial market where market participants purchase and sell electric energy at financially binding day-ahead prices for the following day.
Deemed Contact for Difference (Deemed CfD)	An option in the consultation that removes the link between an asset's metered generation and payment/clawback amounts by using a combination of asset-specific data to estimate what individual asset's generation output should have been at any given point.
Demand Reduction (DR)	In the context of this consultation demand reduction refers to the permanent reduction of electricity demand delivered through installation of electrical energy efficiency measures, for example insulating an electrically heated building or replacing industrial

	appliances for more efficient versions. At a sector-wide level, demand reduction refers to limiting the increase in demand implied by electrification, as opposed to reducing overall demand from current levels.
Demand-side response (DSR)	Also known as flexible demand, is when consumers or businesses respond to market conditions by changing how much and/or when they consume energy.
De-rating factors	De-rating factors are applied to all forms of electricity generation in the Capacity Market to reflect that 100% of capacity will not be available 100% of the time. This is because generating plant can break down from time to time, and wind and solar output varies day to day.
Dispatchable generation	Dispatchable generation refers to sources of electricity that can be produced on demand, according to market need.
Dispatchable Power Agreement (DPA)	A DPA is a private law contract between a carbon emitting electricity generator and Government which sets out the terms for capturing and storing carbon and the compensation which the generator will receive in return.
Distribution Network Operator (DNO), and Distribution System Operator (DSO)	Distribution Network Operators are the regulated companies that own and operates the power lines and infrastructure that connect the grid to properties. Distribution System Operation refers to the active management of the distribution system at the local level.
Electricity Market Reform (EMR)	A set of reforms (including the Contracts for Difference and Capacity Market) introduced by the government in 2013 to incentivise investment in secure, low carbon electricity.
Electricity System Operator (ESO)	In the GB electricity system, the ESO performs several important functions, from second-by-second balancing of electricity supply and demand, to developing markets and advising on network investments.
Emissions performance standard (EPS)	A standard which limits CO2 emissions from any new power station to 450 gm/kWh and prevents new coal fired generation from being built without carbon capture and storage technology.
Emissions Trading Scheme (ETS)	The UK ETS replaced the UK's participation in the EU ETS on 1 January 2021. Emissions trading schemes usually work on the 'cap and trade' principle, where a cap is set on the total amount of certain greenhouse gases that can be emitted by sectors covered by the scheme. This limits the total amount of carbon that can be emitted and, as it decreases over time, will make a significant contribution to how we meet our net zero 2050 target and other legally binding carbon reduction commitments.
Financial Transmission Rights (FTRs)	Financial Transmission Rights allow market participants to offset potential losses (i.e. hedge) related to the price risk of delivering energy to the grid. They are a method to bypass congestion

	charges associated with Locational Pricing. They give market participants the ability to attain a better price certainty when delivering energy across the grid.
Flexibility	The ability to shift the consumption or generation of energy in time or location. Flexibility is critical for balancing supply and demand, integrating renewables and maintaining the stability of the system. Flexibility technologies include electricity storage, flexible demand, CCUS, hydrogen power and interconnectors.
Fossil fuels	A fossil fuel is a naturally occurring hydrocarbon containing material. Examples include crude oil, natural gas, and coal. Fossil fuels are highly combustible and have been the main source of energy across the world.
Frequency response	The Electricity System Operator (ESO) have an obligation to control system frequency at 50Hz plus or minus 1%. There are several different types of frequency response that the ESO procure.
Future Energy Scenarios	These are produced by the Electricity System Operator and represent a range of different, credible ways to decarbonise our energy system as we transition towards net zero.
National Energy System Operator (NESO)	Government has taken powers, as part of the Energy Act 2023, to set the legislative framework for a new, publicly owned NESO (referred to as Independent System Operator and Planner in legislation). We are establishing NESO as an expert, impartial body at the heart of the energy sector with objectives to drive progress towards net zero while maintaining energy security and minimising costs for consumers. NESO will take on responsibilities across electricity, gas and hydrogen, including all the existing functions of the Electricity System Operator (ESO), defined earlier in this glossary, so it is able to take an enhanced whole system approach to planning and operating the energy sector. New roles for NESO include undertaking whole energy system strategic and spatial planning and providing advice to government and Ofgem to inform key policy decisions
Government support schemes	A scheme established by the Government, for example that financially supports participation in electricity wholesale markets.
Green Power Pool (GPP)	An incremental variation on the Split Market - a voluntary, centrally co-ordinated pool for renewable electricity operating alongside the wholesale market. In a GPP, generators would sign government-backed fixed price contracts with the pool to sell output at their long-run marginal cost; suppliers and large consumers would contract with the pool to buy agreed volumes of power. We have discounted this option in this consultation – see Challenge 1.

Inertia	Inertia is important to the stable operation of the electricity system. Many generators producing electricity for the grid have spinning parts – they rotate at the right frequency to help balance supply and demand and can spin faster or slower if needed. The kinetic energy 'stored' in these spinning parts is system inertia. If there's a sudden change in system frequency, these parts will carry on spinning – even if the generator itself has lost power – and slowdown that change (called the rate of change of frequency, or ROCOF) while the Electricity System Operator's control room restores balance.
Inframarginal rents	The difference between the clearing price in an auction or market, and a plant's costs of committing to remain available.
Interconnector	An electricity interconnector runs under the sea, underground or via overhead cabling, to connect the electricity systems of two markets. It allows the trading and sharing of surplus electricity.
Intermittent Market Reference Price (IMRP)	The reference price used for variable renewables with a Contract for Difference (CfD). When the reference price is below the Strike Price, payments are made by Low Carbon Contracts Company (LCCC), defined below, to the CfD Generator. When the Reference Price is above the Strike Price, the CfD Generator pays LCCC the difference. The IMRP is calculated using day- ahead market data, the IMRP is calculated for every hour of the day.
Legacy Arrangement	A contract or set of arrangements governing participation in electricity wholesale markets which was or may be agreed before a public decision on proposals made as part of REMA. These are contracts or sets of arrangements agreed in accordance with Government Support Schemes.
Legacy asset	An asset used in the generation, transmission, distribution or supply of electricity which is the subject of a Legacy Arrangement.
Locational imbalance pricing	Introduces imbalance charges for suppliers if there is both an imbalance and a constraint between the location of their consumers' demand and their generators' supply. This has now been discounted as a policy proposal.
Locational pricing	Locational pricing, also known as locational wholesale pricing, is a way for wholesale electricity prices to reflect the value of electricity at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system.
Locational signals	Pricing signals from generating assets which would incentivise or disincentivise generators to change electricity output to the grid based on changing electricity demand in a particular location.

Long-run marginal cost	The marginal cost is the change in the total cost that arises when an additional unit is produced. The long-run marginal cost includes any fixed costs of production, for example the construction cost of a generator.
Loss of Load Expectation (LoLE)	LoLE is a generation reliability standard metric. It is the expected number of hours per year that electricity generation cannot meet electricity demand.
Low Carbon Contracts Company (LCCC)	A government-owned company that is operationally independent and manages the Contracts for Difference scheme at arm's length from government.
Marginal pricing	Means that the cost of the most expensive generation asset required to meet demand sets the price for the entire market. Currently, due to the current role of gas generation within the GB electricity market, the GB wholesale electricity price tends to closely track gas prices, which are largely set by global market developments.
Market liquidity	Market liquidity describes the extent to which an individual or firm can quickly purchase or sell an asset in a market without causing a drastic change in the asset's price. Liquidity involves the trade- off between the price at which an asset can be sold, and how quickly it can be sold.
Market-Wide-Half-Hourly Settlement	Settlement reconciles differences between a supplier's contractual purchases of electricity and the demand of its customers. Generators and suppliers trade electricity in the wholesale market in half-hourly periods.
Merit Order	A way of ranking available sources of energy, especially electrical generation, based on ascending order of price (which may reflect the order of their short-run marginal costs of production) together with amount of energy that will be generated.
Mid-merit	Refers to generating plants that fall in the middle of merit order (i.e. plants that tend to have short-run marginal costs and load factors that are neither relatively low nor high).
Minima	Where all technologies continue to compete in the same auction, but a mechanism is introduced to allow different clearing prices to be determined for desirable characteristics.
Negative pricing rule	A rule within the Contracts for Difference (CfD) scheme implemented in allocation round four so that support payments are not to be made in any periods where the day-ahead market price (the CfD reference price) is negative.
Net Zero Strategy	This strategy, published in October 2021 by UK Government, sets out policies and proposals for decarbonising all sectors of the UK economy to meet our net zero target by 2050.

Network constraint costs	The Electricity System Operator (ESO) needs to balance the generation and demand across the network. Sources of generation and the points of demand are not always located in the same place. This can lead to bottlenecks on the system as there can be limited capacity to transmit the electricity across the different locations. Where the energy is restricted in its ability to flow between two points this is known as a constraint and the ESO needs to take action to mitigate these constraints. Generators are asked to reduce their output to maintain system stability and manage flows on the network and are compensated through a constraint payment.
New Electricity Trading Arrangements (NETA)	The electricity market trading arrangements introduced in 2001 in England and Wales. In 2005 NETA was developed into the British Electricity Trading and Transmission Arrangements (BETTA).
Nodal pricing	Also known as Locational Marginal Pricing (LMP). An electricity market design where the price in each network location (also known as a "node") represents the locational value of energy.
Offshore Transmission Network Review	The review which concluded in May 2023 looked into the way that the offshore transmission network is designed and delivered, consistent with the ambition to deliver net zero emissions by 2050.
Peaking plant/ "Peaker"	Electricity generators that do not normally operate but are ready to do so when needed at times of peak demand or low generation.
Power Carbon Capture Utilisation and Storage (PCCUS)	Gas-fired power generation with CCUS technology.
Power Purchase Agreement (PPA)	A long-term contract between power producers (typically generators) and a buyer (often a utility or consumer) that might include conditions for when power is supplied and how imbalances are resolved or else the buyer agrees to take all power on an 'as produced' basis. A Corporate Power Purchase Agreement (CPPA) is a PPA between a producer and a corporate buyer, often via an intermediary or 'sleever'. CPPAs are often long-term agreements (e.g. 10 years) and often provide at least a degree of price certainty for the producer, helping them secure financing for construction.
Price cannibalisation	As renewable generation is correlated, wholesale electricity prices are reduced at times of high output from intermittent, weather- driven generation such as solar, onshore and offshore wind. This reduces the revenue that renewable generators can earn in the wholesale market.

REMIT	REMIT provides a regulatory framework for the wholesale energy market, outlines market rules and prohibits market abuse among other functions.
Renewable Energy Guarantees of Origin scheme (REGO)	The REGO scheme provides transparency to consumers about the proportion of electricity that suppliers source from renewable electricity.
Retail Market Reform Programme	The UK government's retail market reform programme is forward looking and pursuing targeted reforms aimed at making the retail market work better for consumers, become more resilient and investable, and support the transformation of our energy system.
Revenue = Incentives + Innovation + Outputs (RIIO- 2)	The framework used by Ofgem to ensure that individual network companies provide a safe and reliable service, value for money, maximise performance, operate efficiently, innovate, and ensure the resilience of their networks for current and future markets. RIIO-2 is the second set of price controls implemented under this framework.
Revenue cap and floor	A mechanism that means that an operator's market revenue over a certain period – for example 15 years – is assigned a maximum (the cap) and a minimum (the floor). The contract period is divided into 'reconciliation periods' (e.g., 1-5 years). Revenue above the cap in a given reconciliation period is returned to funders (e.g., taxpayers or energy consumers), and revenue below the floor in a given reconciliation period is topped up by funders to the floor level.
Short-run marginal cost	The marginal cost is the change in the total cost that arises when an additional unit is produced. The short-run marginal cost excludes fixed costs. For electricity generators, construction costs are fixed therefore only operating costs, such as fuel costs, are included in short-run marginal costs.
Small-scale renewables	Renewable generators with installed capacity below 5MW.
Smart Export Guarantee (SEG)	The SEG was introduced in 2020 and requires retail suppliers with more than 150,000 domestic customers to offer at least one export tariff to any generator with an eligible <5MW installation.
Split Market	An option that would involve the splitting of the wholesale market in two: the creation of a separate market for renewables, with prices set on the basis of the long-run marginal costs (i.e. integrating renewable investment into the wholesale market), alongside a separate market for flexible, dispatchable assets where the price would continue to be set by short-run marginal cost. We have discounted this option in this consultation – see Challenge 1.

This consultation is available from: <a href="http://www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation">www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation</a>

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