

Review of Electricity Market Arrangements

Second Consultation Document

Closing date: 7 May 2024



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Any enquiries regarding this publication should be sent to us at: remamailbox@energysecurity.gov.uk

Foreword

After a period of unprecedented disruption and change, the UK energy sector is now poised to seize the opportunities of the energy transition. Through a huge package of support, we have protected consumers from the worst impacts of high global energy prices, triggered by Russia's invasion of Ukraine. We have introduced the Energy Act 2023 – the biggest piece of energy legislation in the UK's history – to build an energy system fit for the future. Working with industry, we have set parameters for the upcoming Contracts for Difference round (AR6) to boost investment in GB and further cement our position as a global leader in clean energy. We have set out major plans to speed up grid connections and rapidly increase capacity on the electricity grid. This consultation will help us deliver our objectives, to ensure our electricity markets are fit for future purpose, and to prepare our electricity system for full decarbonisation by 2035, subject to security of supply.

Effective market arrangements – whether wholesale, retail, or specific to objectives such as accelerating decarbonisation – are key to delivering a low-cost system, driving down both the cost of power itself as well as the infrastructure needed to deliver it to consumers. This consultation sets out a range of reform options which have the potential to save tens of billions from people's bills. As the system evolves around us, 'do nothing' is not an option – existing arrangements will get harder to operate and lock in a high-cost path to transition. Our analysis suggests that reforming our electricity markets could reduce overall system costs by £35 billion from 2030 to 2050, and potentially by even more than that. This is a key reason to fully explore the potential for significant change.

It recognises that whilst rapid progress to decarbonise is an imperative, the transition must proceed in a secure and orderly fashion. Renewable generation must be complemented by flexible power for the times when the wind is not blowing for example. While we build out these new sources of low carbon flexibility via batteries, Carbon Capture Usage & Storage (CCUS), hydrogen and more, we will never put at risk the UK's security of electricity supply. This means we will continue to need a limited amount of gas-fired generation as a back-up, so we will extend the life of some of our ageing unabated gas assets, where that is needed for our security of supply and it is safe and practical to do so. But new build will be required too. That is why we will also build a limited amount of new build, traditional gas capacity capable of providing sustained flexible capacity in the short-term, at the same time as ensuring a smooth transition to low carbon flexible generation sources in future. The alternative is to risk blackouts – that is not a risk any household or business would want us to take.

This is also an opportunity to future-proof our wholesale electricity market and help unlock massive investment in a cost-effective and secure energy system – £275-375bn in new capacity could be required. This will need the private sector working alongside government, the regulator and the system operator to help design future markets with the characteristics necessary for such large-scale investment. We have made significant progress narrowing down options for electricity market reform through the Review of Electricity Market Arrangements (REMA) programme. This consultation sets out the lead options alongside a clear timetable to complete the programme's work. This will continue to strengthen electricity security and support our delivery of net zero while helping keep energy bills down for consumers in the long-term, protecting the environment in an ambitious and practical way.

The Rt Hon Claire Coutinho MP

Secretary of State for Energy Security and Net Zero

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General information

Why we are consulting

The government made a commitment in the British Energy Security Strategy to undertake a comprehensive review of electricity market design, to ensure that it is fit for the purpose of maintaining energy security and affordability for consumers as the electricity system decarbonises. Effective markets will be key to delivering the most efficient energy mix through the transition to a decarbonised economy, and it is critical that those markets are properly set up to deliver affordable, secure, and clean energy. This will become even more important as we move to greater electrification of heat, transport and industry over the coming decade. This consultation explores options to deliver an enduring market framework that works for our businesses, industry, and households, and builds on our first consultation published in summer 2022.

Consultation details

Issued: 12 March 2024

Respond by: 11:59pm on 7 May 2024

Enquiries to:

Email: remamailbox@energysecurity.gov.uk

REMA Team Department for Energy Security and Net Zero Floor 5 3-8 Whitehall Place London SW1A 2AW

Consultation reference:

Review of Electricity Market Arrangements - Second Consultation

Audiences:

Energy industry, NGOs, consumer groups, academics, policy think-tanks

Territorial extent:

Energy policy is reserved and REMA applies across Great Britain

How to respond

Responses should be provided online at: <u>https://energygovuk.citizenspace.com/clean-electricity/review-of-electricity-market-arrangements-rema-sec</u>

Or

Write to:

REMA Team Department for Energy Security and Net Zero Floor 5 3-8 Whitehall Place London SW1A 2AW

When responding, please state whether you are responding as an individual or representing the views of an organisation.

Your response will be most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

To make our analysis as efficient as possible, we would prefer responses to come via the Citizen Space link above. However, if this is not possible, then please either write to us, or email your response to <u>remamailbox@energysecurity.gov.uk</u>.

Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential, then please tell us, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our <u>privacy policy</u>.

We will summarise all responses and publish this summary on <u>GOV.UK</u>. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's <u>consultation</u> <u>principles</u>.

If you have any complaints about the way this consultation has been conducted, please email: <u>bru@energysecurity.gov.uk</u>.

Executive Summary

Markets are at the heart of the GB electricity system. They drive competition and innovation to benefit consumers. They 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. Reforming electricity markets through the Review of Electricity Market Arrangements (REMA) programme is vital to the delivery of the government's plan to deliver a fully decarbonised electricity system by 2035, subject to security of supply.

Our underlying electricity market arrangements were adopted in an era of large, centralised, unabated fossil fuel-based generation – with power available at the touch of a button. The previous major round of electricity market reform (which ran from 2010-13) focused on how best to scale-up low carbon renewable generation in a power system still largely designed for fossil fuel technologies – by accelerating the journey to a renewables-based system through a new Contracts for Difference (CfD) scheme while ensuring security of supply by introducing the Capacity Market (CM) scheme. The purpose of the REMA programme is to create the market arrangements to complete this move to low carbon technologies, managing a smooth and low-cost transition away from our remaining unabated fossil fuel generation capacity, while maintaining security of supply.

The UK is leading the world here: no major economy has yet made the transition from an electricity system based on fossil fuel-based generation to a fully decarbonised one. Since 2010, we have built 43GW¹ of renewables including the five largest offshore windfarms in the world, and we have slashed coal, the dirtiest of fossil fuels, which provided more than a quarter of our power in 2010, to the extent that our last coal power station will close later this year. This has reduced emissions from our power sector by around 65%² whilst maintaining high levels of security of supply. As a result, we have decarbonised faster than any other major economy.

However, these new technologies – particularly intermittent renewables – have different characteristics from the fossil fuel-based technologies we have previously relied on. Our market arrangements therefore need to evolve to both drive and reflect this transformation in the nature of our electricity system.

It is clear from the responses to our first REMA consultation in 2022, and our engagement with stakeholders since then, that a range of underlying market failures and limitations of existing interventions mean the current electricity market framework will not deliver the secure, clean, low-cost electricity system we need in the future. Delivering this transition will require: a significant acceleration in low carbon capacity including the deployment of new low carbon flexible technologies; clearer decarbonisation pathways for our remaining fossil-fuelled generation and some limited investment in the short-term in new build gas generation to maintain security of supply as existing capacity expires; stable, long-term investment signals and a stronger focus on the efficient and safe operation of the electricity system. REMA therefore aims to establish the enduring market arrangements needed to enable the transition to, and operation of, our future renewables-dominated electricity system.

¹ DESNZ, 2023, Energy Trends, Renewable electricity capacity and generation.

² DESNZ, 2023, Final UK greenhouse gas emissions national statistics: 1990 to 2021.

This second REMA consultation seeks to set out a clear direction of travel for how GB electricity market arrangements will need to evolve in future.

We have structured our thinking around four key challenges facing electricity markets, while also considering the interactions between these challenges given the need for an integrated, whole-system approach. These are:

- Passing through the value of a renewables-based system to consumers
- Investing to create a renewables-based system at pace
- Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system
- Operating and optimising a renewables-based system, cost-effectively

Within each of these four key challenges, we have assessed the different policy options against five criteria – value for money, deliverability, investor confidence, whole-system flexibility, and adaptability – as well as wider considerations including statutory obligations. We have considered both the need for a significant ramp up in investment in all forms of low carbon technologies and the need for a system that can be operated as efficiently and cost effectively as possible.

Based on our assessment, in this second REMA consultation we are seeking stakeholder views on some specific proposals and a short-list of remaining options. While the REMA programme runs, all existing schemes will continue to provide important stability for investors and market participants, and clarity for consumers and other stakeholders. As part of this consultation, we explore how Legacy Arrangements (those agreed under Government Support Schemes prior to a public decision on REMA reforms) and Legacy Assets may be impacted, and how potential new risks from reform options may be mitigated.

The proposals set out in this second REMA consultation reaffirm the central role of markets at the heart of our future electricity system. Our work on electricity markets is only one part of a 'whole system' approach to support the delivery of a fully decarbonised electricity system by 2035, subject to security of supply. Changes to electricity markets will need to work alongside a range of wider policy actions underway to accelerate the pace of network build, reduce connection timescales and take a more strategic and co-ordinated approach to spatial planning for energy infrastructure.

Alongside this consultation document, we are publishing an Options Assessment which provides additional details regarding the analytical frameworks and bespoke analysis that have been produced to support the policy development process. We are also publishing a number of external research reports that have helped inform the options assessments. These are more detailed technical documents on particular issues, which are referred to later in this document.

Summary of REMA Proposals

Summarised below are the proposals in this consultation, set out by the key challenges.

These proposals reflect extensive research, policy development and analysis, and take into account the needs of industry, investors, consumers (both domestic and non-domestic) and the system as a whole. For a more detailed assessment of these proposals and the options that we have discounted, see the relevant challenge sections and the Options Assessment.³

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

- Retain marginal pricing across the wholesale market and future-proof the CfD scheme the combination of these two approaches is the best way to decouple gas and electricity prices and enable efficient electricity system operation.
- Discount options of a Split Market or Green Power Pool, which we do not consider to be deliverable and would not provide additional benefits to consumers even if they could be delivered.
- Monitor the evolution of the Corporate Power Purchase Agreement (CPPA) market, where we believe there could be significant room for growth. We are interested in the potential impacts of REMA reform on the growth and role of that market in driving new low carbon generation.
- Pursue a cross-cutting approach to incentivising electricity demand reduction through improving our assessment of the whole system value of demand reduction, and potential strengthening of price signals within electricity and retail markets, complemented by the existing portfolio of energy efficiency policies in downstream markets.

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

- Commit to retain a CfD-type scheme as the primary and most effective mechanism for driving investment in renewable generation to deliver net zero. The CfD has been a transformative intervention, and we will build on that foundation.
- Ensure the CfD scheme is future-proofed by consulting further on a range of reform options. These include moving away from payment based on output (e.g. by deeming CfD payments or moving to a capacity-based CfD), reference price reform, and restricting the percentage of capacity the CfD would cover for any development.
- Discount a 'strike price range' for CfD assets and a 'revenue cap and floor' as they perform poorly against our assessment criteria. A strike price range would introduce significant extra risk for developers, with potentially limited system benefits. A revenue cap and floor for renewables has several design flaws that could lead to significant gaming risk or distort incentives for generators to operate efficiently, leading to consumer detriment.

³ In-depth information on the rationale for discounting options can be found in the accompanying REMA Options Assessment. Available at: <u>https://assets.publishing.service.gov.uk/media/65eb45ae5b652445f6f21b30/rema-options-assessment.pdf</u>

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

- Retain the Capacity Market (CM) as our primary mechanism for ensuring capacity adequacy. A range of alternative options have been discounted as they were found to be less effective. We will continue to implement shorter-term reforms to the CM to ensure the scheme continues to support security of supply effectively.
- Progress the development of bespoke policy to support technologies such as Power CCUS, Hydrogen to Power (H2P) and Long Duration Electricity Storage (LDES) to mitigate emerging technology risks. This includes plugging current gaps in our policy framework through separate consultations on our minded to position that a business model to support H2P may be needed and developing a support scheme for LDES.
- Optimise the CM by introducing a minimum procurement target (otherwise known as 'minima') into the auction to better support investment in low carbon flexible technologies. In the long-term, the Optimised CM should be the primary scheme for supporting the deployment of a competitive mix of low carbon flexibility. We will keep progress of all low carbon flexible technologies in receipt of bespoke support under review until we have confidence that they are able to compete in an Optimised CM.
- Set out updated expectations of the amount of flexibility we will need on the electricity system in 2035, specifically a range of internal and external models estimate that the GB electricity system could require up to 55GW of short-duration flexibility and between 30 and 50GW of long-duration flexibility.
- Develop clear decarbonisation pathways for unabated gas to ensure a glide path to a fully decarbonised electricity system. Based on our internal analysis we expect that a limited amount of new gas capacity will be required in the immediate term to ensure a secure and reliable system that avoids blackouts. It is the only mature technology capable of providing sustained flexible capacity whilst low carbon long duration alternatives, such as Power CCUS, H2P and LDES scale up.
- Promote sustained investment in the extensive build-out of low carbon flexible capacity and supporting infrastructure to secure electricity supply through to 2035 and beyond. To ensure clear decarbonisation pathways for our remaining unabated gas generation, greater hydrogen and CO₂ infrastructure would need to be available in future. This will require public policy frameworks to leverage private finance.
- Work with Ofgem, the National Energy System Operator (NESO) and industry to accelerate progress and reforms within the current market framework to support distributed flexibility, and review whether additional steps are needed.

Challenge 4 - Operating and optimising a renewables-based system, costeffectively

• Consider strengthening locational signals in the market by assessing two options: zonal pricing (which would send wholesale market participants both locational investment and operational signals); and a set of alternative options (which are likely to primarily send locational investment signals) which could be implemented under current national pricing arrangements. This includes working with Ofgem on reforms to network charging and transmission access in parallel with REMA reforms.

- Discount nodal pricing due to the impacts it would have on investor confidence and the deliverability of our 2035 decarbonisation targets.
- Consider centralised dispatch, alongside the option of a reformed Balancing Mechanism. We will also continue to consider other reforms to existing arrangements such as shorter settlement periods.
- Work with NESO, Ofgem and wider stakeholders to develop proposals for an electricity system operability strategy for 2035, better forecasting of operability needs and improved emissions reporting by NESO. We will also investigate perceived barriers to the provision of ancillary services from co-located assets and how alignment of 'longerterm' ancillary services with CfD auctions could be achieved.
- Discount the 'local markets' model, which aimed to reorient the wholesale market around local, distribution-level markets, and instead continue to consider what further actions are needed in order to deliver open, dynamic and coordinated markets for distributed low carbon flexibility, as discussed in Challenge 3.
- Consider further the impacts of REMA reforms on market liquidity.

Options Compatibility and Legacy Arrangements

- Take an appropriate whole-system perspective to identify the optimal combination of reforms to deliver the transition to and operation of our future renewables-dominated power sector. We have already identified a high level of compatibility across the remaining options under consideration in our initial assessment.
- Assess further the impacts of REMA options on existing assets and participants in respect of Legacy Arrangements in the next phase of the programme. We will assess impacts of remaining REMA reform options on a scheme-by-scheme basis – i.e. to consider, in turn and distinctly from each other (rather than taking a blanket approach).
- Confirm with respect to locational pricing, legacy CfD contracts (including all those agreed until a public decision on REMA, including AR6) would likely be amended to use a local reference price if this reform was introduced. This would ensure legacy CfD holders still achieve their strike price when they generate and are insulated from locational price risk for the duration of their contract.

Next steps

Our reforms must work for a diverse range of stakeholders covering the breadth of supply of and demand for electricity. There are significant interlinkages and dependencies across all technologies, markets and regulations. Therefore, we will continue to engage extensively and transparently across the sector.

We welcome the work done and feedback received from a diverse range of stakeholders – including consumers (both domestic and non-domestic), Ofgem, NESO, academia, think tanks, Non-Governmental Organisations (NGOs), and industry – to support this next phase of REMA.

This consultation will remain open to written responses for 8 weeks. The government will use the consultation responses and evidence submitted to inform further policy development and our thinking on the best allocation of risk in a renewables-dominated system. As shown in Figure 1, we expect to provide a summary of responses in summer 2024. We intend to conclude the policy development phase of the programme by mid-2025 and move into full-scale implementation from 2025 onwards, or earlier where we can.

Figure 1: REMA Milestones

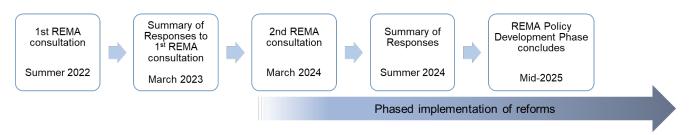


Figure 2 shows how the proposals set out in the first REMA consultation have progressed. In the next phase of REMA, we will continue to consult and work with stakeholders to develop a detailed assessment and design of remaining policy options, how they interact with each other, and how to manage the transition to new arrangements. A system which allocates risk and incentives to those best placed to minimise such risks and maximise opportunities is key to an efficient, stable and enduring market regime. We will explore this in further detail in the next phase of the programme.

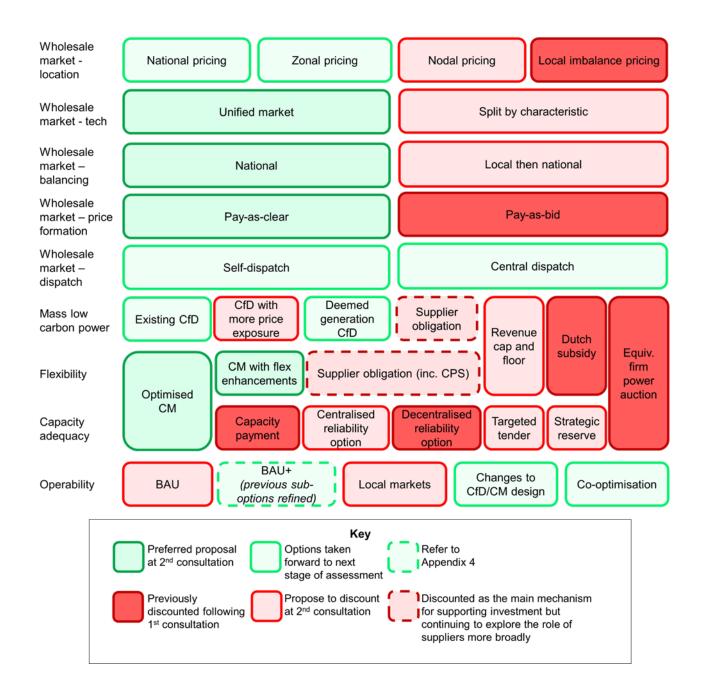


Figure 2: How the options from the first REMA consultation have progressed

Introduction: Our vision for the electricity market of the 2030s and beyond

Section summary

One of the cornerstones of a prospering economy is access to affordable, clean and reliable energy. We rely on it to power our homes, businesses and infrastructure. Decarbonising the electricity system is a critical enabler to decarbonising other sectors of our economy. This is why the government is aiming, by 2035, to deliver a fully decarbonised electricity system, subject to security of supply.

Delivering our ambitions for the electricity system will require huge investment at pace in a wide range of generation and flexible technologies, and networks to be deployed in a way that benefits the overall system. Rapid deployment of low carbon technologies will be key to minimising security of supply risks whilst meeting our net zero targets.

The REMA programme will future-proof our electricity market arrangements to: help unlock unprecedented levels of investment across the full range of low carbon technologies; maintain security of supply; and ensure that our future renewablesdominated system can be operated safely and cost-effectively.

This section sets out:

- our successes to date in harnessing cleaner, greener electricity across the country
- how government is delivering whole system outcomes beyond market frameworks
- the important role of markets within our approach
- key considerations for designing a set of enduring market arrangements that deliver against REMA's vision and objectives
- REMA's progress so far, aims of this consultation and our approach for assessing REMA options and developing proposals, including assessment criteria and the four key challenges for our future electricity markets that we have used to frame this consultation

Getting the GB electricity market arrangements right is critical to helping deliver the energy transition and net zero. Markets provide price signals that guide decisions on electricity supply and demand, investment in new capacity for generation, deployment and utilisation of flexibility, and the efficient operation of the system.

We need to ensure that our electricity markets are fit for purpose over the period to 2035 and beyond, to unlock the full potential of low carbon technologies for the benefit of consumers, reduce our reliance on fossil fuels and enhance security of supply. That is why the British Energy Security Strategy announced the launch of a comprehensive Review of Electricity Market Arrangements in April 2022.

We have made great progress towards net zero, reducing greenhouse gas emissions by 48% since 1990 across the UK economy.⁴ Our electricity markets have driven significant decarbonisation since 2010: we have built 43GW⁵ of renewables and moved away from almost all coal generation, with GB's last coal power station due to close in 2024. This has reduced emissions from our power sector by around 65%⁶ compared to 2010 levels, whilst maintaining high levels of security of supply. As a result, we have decarbonised faster than any other major economy.

Our success in reducing emissions from the power sector over the last ten years has been driven in large part by the changes introduced as part of the **Electricity Market Reform (EMR) package in 2013.** EMR accelerated the journey to a renewables-based system through the new CfD scheme, and also introduced the CM scheme which has succeeded in ensuring security of electricity supply. Thanks to EMR, the CfD and CM schemes have supported around 30GW and 17.5GW of new capacity respectively.⁷

But more needs to be done. In 2022/23, 56% of total electricity generation came from low carbon sources, and 39% from gas generation.⁸ Meeting our commitment to deliver a fully decarbonised electricity system by 2035, subject to security of supply, requires the majority of low-carbon technologies, including offshore wind and nuclear power, to deploy at or close to the maximum level technically feasible in that time. It will need us to drive unprecedented levels of investment in low carbon technologies⁹ – and to manage a smooth and secure transition away from unabated gas generation as cost-effectively as possible. As older plants retire, and as demand increases through the rapid electrification of heat and transport, we have a large future capacity requirement.

At the same time, the electricity system is also becoming less centralised as more renewables are connected at the local level and consumers increasingly adopt smart devices, electric vehicles, solar panels, heat pumps and other assets, engaging more actively in the energy market.

In future, more of our generation capacity will be located far from demand – where natural resources such as wind are most plentiful. The increasing volume of variable renewables, especially wind and solar power, will pose greater challenges for managing the electricity system and is changing the nature of the security of supply challenge.

Our electricity system will increasingly need to manage more complex 'stress events' ranging from periods of more renewable generation than we need through to potential prolonged periods of low supply from renewable generation (for example, extended periods of low wind supply during high demand in winter). At the same time, sufficient unabated gas-fired generating capacity will need to remain available during the transition period to ensure security of supply whilst facilitating routes for these assets to decarbonise. Based on our internal analysis we expect that a limited amount of new build gas capacity will be required in the

⁴ DESNZ, 2023, Final UK greenhouse gas emissions national statistics: 1990 to 2021.

⁵ DESNZ, 2023, Energy Trends, Renewable electricity capacity and generation.

⁶ DESNZ, 2023, Final UK greenhouse gas emissions national statistics: 1990 to 2021.

⁷ Based on DESNZ internal calculations: <u>https://www.emrdeliverybody.com/CM/Registers.aspx</u>.

⁸ DESNZ, 2023, Energy Trends. Fuel used in electricity generation. Available at:

https://assets.publishing.service.gov.uk/media/65130cd43d371800146d0c1c/ET_5.1_SEP_23.xlsx based on DESNZ internal calculations.

⁹ Short-duration flexibility includes technologies such as batteries and demand-side response. Long-duration flexibility includes technologies such as pumped hydro storage, hydrogen-to-power (H2P), long-duration large-scale electricity storage (LDES) or power Carbon Capture Usage and Storage (CCUS).

immediate term to ensure a secure and reliable system as older plant retires. We are developing clear decarbonisation pathways for unabated gas generation to ensure a glide path to a fully decarbonised power sector by 2035, subject to security of supply.

Our electricity market arrangements need to be updated to manage these challenges. The focus of our work within the REMA programme is the transition to and operation of the renewables-dominated electricity system of the 2030s. However, these reforms will also put us on a pathway to meet our economy-wide 2050 net zero target.

Delivering 'whole system' outcomes

Supporting the anticipated growth in low carbon generation and demand, while ensuring a secure and resilient electricity system, requires a transformation at a scale and pace unprecedented since the mid-20th century. The scale of action required to meet our 2035 ambitions for the power sector means that we must act quickly, and we must continue to leverage private sector investment throughout the transition.

Alongside this, we are facing a set of new risks and opportunities. For example, immature technologies need a level of bespoke support to de-risk investment and manage cross chain risks (such as a reliance on infrastructure that is not yet in place) to enable them to deploy at scale.

Our case for change – as set out in the first REMA consultation – concluded that there are a range of underlying market failures and limitations of existing interventions which mean that the current electricity market framework will not deliver the investment in the kinds of technologies at the capacity that we need.

There is therefore a strong case for continued intervention to deliver our objectives for a decarbonised and secure electricity system by 2035 in the way that provides best value for money for consumers. We will pursue solutions which maximise the role of the market and drive competition between technologies where possible and when appropriate to drive a cost-effective system and spur innovation.

In addition, there is a crucial role for government to provide an over-arching vision for the power system: to establish priorities, set direction and make underpinning choices that guide market behaviours. Markets are a critical part of the picture, but so are a range of factors that will complement markets and help optimise physical networks and ensure a coherent whole. There will be choices for both investors and government to make concerning where and how network assets are best deployed, and the optimal approach will depend on the development, deliverability, and costs of different solutions, as well as the level of demand for electricity from sectors such as heat and transport.

To help respond to this we are implementing a 'whole system' approach to overseeing the government's activity to support delivery of our ambitions of a fully decarbonised electricity system by 2035, subject to security of supply. We use portfolio management and analytical techniques to consider potential options, measure uncertainty, and manage risks, issues, assumptions and dependencies. This is overseen through robust governance arrangements, to support ministers in making well-informed strategic decisions. Work is already underway across government to improve strategic planning of network infrastructure, including the Holistic Network Design; improve the planning and consenting process; reduce community

impacts through the strategic approach to network design; and expedite Ofgem's regulatory approval process.

We recognise that we need to go further and have recently published a 'Transmission Acceleration Action Plan' (the government's response to recommendations from the Electricity Networks Commissioner, Nick Winser)¹⁰ and the joint government-Ofgem 'Connections Action Plan', on reform to the process for connecting new projects to the grid.¹¹ The work progressed under REMA will reduce the amount of additional investment needed in networks by lowering peak demand and reducing costly network upgrades.

Given the scale and pace of change required, there will be a role for central institutions such as the government, Ofgem and the National Energy System Operator (NESO) to help facilitate our pathway through the energy transition, ensuring interconnected policies and markets work in a cohesive manner. Delivering our objectives will therefore require a level of coordinated, strategic decision-making.

The government has taken powers in the Energy Act 2023 to establish a new, publicly owned Future System Operator, which will be known as the National Energy System Operator (NESO). NESO will be a trusted and expert 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), 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 system strategic planning, with the first Centralised Strategic Network Plan due in 2026, and providing advice to government and Ofgem to inform key policy decisions. We are aiming for NESO to be operational in 2024, subject to agreeing timelines with key parties. The Prime Minister also announced in September 2023 that we will take a more strategic and co-ordinated approach to spatial planning for energy infrastructure. In consultation with Ofgem and ESO, and with input from the Devolved Administrations, the government will commission the ESO, in advance of becoming NESO, in early 2024 to work with government to produce a Strategic Spatial Energy Plan (SSEP). The SSEP will set out the optimal location of generation and storage infrastructure needed to meet forecast demand and our 2050 targets. This will enable us to provide industries with the certainty they need and the creation of a transmission network blueprint in the Centralised Strategic Network Plan.

The government laid the Strategy and Policy Statement (SPS) for GB Energy Policy in Parliament on 21st February 2024. The SPS is intended to provide guidance to the energy sector on the actions and decisions that are needed to deliver government's policy goals and places emphasis on where government expects a shift in the energy industry's strategic direction. The Secretary of State, Ofgem and NESO will be required to have regard to the strategic priorities in the SPS when carrying out their functions.

This statement will therefore support strategic alignment between government, Ofgem, NESO and industry, making clear what government wants to achieve in the energy sector, including enabling anticipatory investment and innovation.

¹⁰ DESNZ, 2023, Electricity networks: transmission acceleration action plan. Available at:

https://www.gov.uk/government/publications/electricity-networks-transmission-acceleration-action-plan ¹¹ DESNZ & Ofgem, 2023, Electricity networks: connections action plan. Available at: https://www.gov.uk/government/publications/electricity.networks.connections.action.plan.

https://www.gov.uk/government/publications/electricity-networks-connections-action-plan

The role of markets within the electricity system

Markets are a critical part of delivering our future electricity system. They send key signals to guide decisions on long-term investments and efficient dispatch, whilst facilitating competition to reduce system costs and ensure fair outcomes for consumers.

The benefits of a market-led approach can be considered in terms of 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; and
- Dynamic efficiency market mechanisms incentivise innovation and technological progress, which underpin the continuous improvement of technologies and discovery of more efficient business models.

If our 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. Market participants have the best information about their own assets, consumer base, and business models. Therefore, where possible we want investment and operational decisions to be driven by participants.

However, in some cases, underlying market failures and limitations of existing interventions mean that markets alone may not deliver our objectives. In practice, there are a broad range of market failures that constrain market mechanisms in delivering efficient outcomes. For the power sector, this is complicated further because the trilemma incorporates not only economic objectives, but diverse and sometimes competing social and environmental objectives too. Our ability to design markets that optimise across these objectives is imperfect.

A balanced approach to the power system therefore harnesses the benefits of market mechanisms, whilst using targeted government interventions to mitigate their shortcomings. The main role of electricity markets should be achieving efficient investment decisions and efficient dispatch decisions. Other government objectives (such as industrial policy, redistributive policy, or monetary policy) are also likely to interact with electricity markets.

Getting the GB electricity market arrangements right is critical to helping deliver the energy transition and should provide the right conditions to incentivise investment required in the power sector but also harness the benefits of 'the market'. These include: encouraging competition between generation technologies to lower the cost of producing electricity; lowering barriers to entry for new market participants; creating the right environment for competition; minimising distortions and externalities by ensuring their economic cost is reflected and captured in the system; and by ensuring there is enough liquidity to enable market participants to effectively manage financial risks through hedging.

The REMA programme focuses on core electricity markets: the wholesale market, Balancing Mechanism, ancillary services, as well as policies that impact these – including the evolution of and alternatives to the CfD scheme and the CM. These markets interact with other parts of the energy system, including other markets such as the emissions trading system or European electricity markets via interconnectors, and we have considered these interactions as part of our work.

Interactions with retail markets

Suppliers buy power in the wholesale market over a variety of timescales to meet the demands of their customers. Suppliers then package this into tariffs for domestic and non-domestic customers, alongside other costs such as network charges, policy costs associated with schemes such as CfDs, and the costs of the ESO's actions to keep the system in balance. Our electricity market arrangements therefore have important impacts on retail markets and consumer demand, while in turn retail market design has important implications for electricity markets.

There are therefore clear interdependencies and synergies between the REMA programme (which is focused on electricity markets) and our parallel programme of work to reform energy retail markets. As we set out in our first REMA consultation, we are considering these market reforms through two separate but interlinked programmes that work side-by-side.

Following the first REMA consultation, government published a package of 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. We published a response to our recent call for evidence on Innovation in the Energy Retail Market in February 2024, setting out the next steps for our ongoing programme of energy retail market reform. The diagram below sets out the key areas within this consultation where we are considering the interactions between the two programmes of work.

Figure 3: REMA interactions with retail markets

Challenge 1 – Passing through the value of a renewables- based system to consumers	Challenge 2 – Investing to create a renewables-based system at pace	Challenge 3 - Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system	Challenge 4 - Operating and optimising a renewables-based system, cost-effectively	
Marginal pricing/split markets – discounting transformational options that would involve	REMA reforms will have implications for components of consumer bills stemming from schemes such as the C CM, and costs associated with balancing and operating the system, and we are seeking to ensure cost-effective for consumers alongside our other objectives.			
suppliers interacting with different markets. Continuing with CfD- type mechanism will likely mean wholesale market costs constitute a declining proportion of supplier costs over time.	Future CfD design - considering impact of options for reforming the CfD, including reference price reform, on liquidity and how suppliers trade in the wholesale market. Also considering their impact on obligation levies for suppliers.	Distributed low carbon flexibility - considering barriers to distributed flexibility, including as part of retail market reform driving more innovative retail services.	Locational signals - considering the impacts of locational wholesale pricing, and alternatives for sending locational signals outside of the wholesale market, on the retail market.	
Power Purchase Agreements - considering how direct arrangements with consumers can facilitate the growth of low carbon capacity.			Improving temporal signals - options such as shorter settlement periods can incentivise the participation of consumers, alongside reforms	
Demand Reduction - cross- cutting approach, including	support investment, including considering the interaction		such as Market-wide Half Hourly Settlement.	
through retail market reform driving more innovative retail services.	with retail markets and schemes run by suppliers.		Balancing and ancillary services – considering impact of potential reforms, including central dispatch, on the retail market.	
			Liquidity - considering liquidity and effects on suppliers' ability to hedge the impact of wholesale price volatility, across the REMA Programme.	

Interactions with interconnected markets

In December 2020 the UK and EU agreed the Trade and Cooperation Agreement (TCA). Implementation of the TCA will enable the efficient trade of electricity over interconnectors, and the relevant energy provisions will specifically support and strengthen the UK and EU's respective energy and climate ambitions whilst ensuring our respective markets are sufficiently compatible to enable efficient electricity trading to take place in an open and fair manner.

In August 2023 we published a response to our consultation on re-coupling GB auctions for cross-border trade with the EU at the day-ahead timeframe. We intend to legislate to achieve a single GB clearing price, subject to engagement with the Specialised Committee on Energy (SCE), industry and stakeholders. We will continue to take account of our international agreements and obligations for energy trading and cooperation, including the development of efficient trading arrangements in the day-ahead timeframe based on the concept of Multi-Region Loose Volume Coupling, as we consider options for reform under REMA.

Effective electricity market design

REMA vision

The government's vision as stated in the first REMA consultation was that our future electricity market arrangements would:

- Deliver a step change in the rate of deployment of low carbon technologies and reduce our dependence on fossil fuelled generation.
- Provide the right signals for flexibility across the system.
- Facilitate consumers to take greater control of their electricity use by rewarding them through improved price signals, whilst ensuring fair outcomes
- Optimise assets operating at local, regional, and national levels.
- Ensure that the security of the system can be maintained at all times.

Responses to the first consultation supported this vision, although stakeholders weighted these components differently. This vision continues to drive the REMA programme.

To achieve this vision, REMA must deliver the transition to a renewables-dominated power system and an enduring set of market arrangements which will enable the efficient operation of such a system. The programme's objectives are:

• Security of supply: Reliable supply and system resilience are maintained throughout the transition to a fully decarbonised electricity system by 2035, by ensuring capacity adequacy and operability. The system adapts to evolving physical and digital challenges and effectively manages short-term and seasonal variations. This will ensure a secure and reliable electricity supply for consumers.

- **Cost-effectiveness.** The pathway to a fully decarbonised power system by 2035 must be cost-effective, providing value for money for consumers and taxpayers by maximising benefits and minimising risks.
- **Decarbonisation:** The power sector meets its sector contribution for carbon budgets and net zero targets and facilitates economy-wide decarbonisation. This means a fully decarbonised electricity system by 2035, subject to security of supply.

In taking final decisions under the REMA programme on our enduring electricity market arrangements there are some key tensions that will need to be balanced. One of these is the need for a significant ramp up in investment in all forms of low carbon technologies, alongside a system that is operated as efficiently and cost effectively as possible, maximising assets' exposure to price signals that reflect system needs across time and location.

Meeting our decarbonisation ambitions and the increased demand from the electrification of heat and transport requires us to deploy renewable and low carbon flexible capacity faster than ever before. To achieve a fully decarbonised electricity system at the pace required we have set out that investment of £275-£375bn in new capacity could be needed. This means the financing cost (the cost of borrowing money and/or the required return) of the capital expenditure will have a large impact on the overall cost of the system. This is why investor confidence is one of our five criteria that we are assessing options against. In Challenges 2 and 3 of this consultation, we set out our thinking and remaining options for supporting this investment at scale.

Alongside ramping up investment, our market arrangements will need to enable the efficient operation of a system where generation output and demand are less predictable, supply is located further from demand, and supply is more decentralised with millions of assets connected at the distribution system. Price signals must reveal the value of flexibility and provide consumers with the tools to engage more effectively with the system. This will enable us to maximise the use of renewable generation and reduce the total amount of generation and network built. We are already seeing a rise in the cost of balancing and system operation which ultimately falls on consumers. In Challenge 4 of this consultation, we set out our thinking and remaining options for addressing these issues and reducing costs.

Another key question for the next phase of the REMA programme will be determining how risks and incentives are most appropriately and effectively allocated¹² between market participants, particularly investors and consumers (the latter often intermediated by government or suppliers). If our market arrangements ensure that risks and incentives fall where they can be best managed and responded to, this is likely to create a more efficient system overall and therefore achieve our objectives at the lowest overall cost. For example, generation asset owners are often best placed to manage the technology and development risks associated with their assets, and appropriate risk exposure can incentivise investors to change their behaviour to manage these risks. In some cases, risks cannot be effectively managed by market participants, for example a range of societal and political risks that are largely outside of generators' control but may impact their return on their investment, increasing the cost of capital. In some cases, appropriate market design can limit or eliminate risks altogether.

¹² We consider this further in our Public Sector Equality Duty assessment that will be carried out as part of the final package of REMA proposals.

The role of risk

The prevalence of risk is a natural and healthy part of any investment proposition. It ensures that actual economic value is reflected, and that investor behaviour is disciplined by forcing them to make choices around how best to allocate their resources in order to generate a return, and in doing so secure economic value over and above what government can provide. In general, investors should not be insulated against all risks.

Through REMA we are aiming to create the set of market arrangements which are most likely to deliver our power sector objectives at the lowest overall system costs, taking account of both cost of capital and system operational costs. As part of this phase of REMA, we have carried out an initial assessment of options compatibility as set out in the Options Compatibility and Legacy Arrangements section, which concludes there is a high level of technical compatibility between options. In the next phase of REMA, we will need to consider the optimal overall system design and then take final decisions on the remaining policy options, guided by that overall system perspective.

Progress on REMA so far and aim of this consultation

Following the launch of REMA in the British Energy Security Strategy in April 2022, we published our first consultation in July 2022.¹³ It sought views on the case for change, options for reforming electricity markets (including wholesale markets, mass low carbon power, flexibility, capacity adequacy, and system operability), options assessment criteria and several programme design and cross-cutting issues.

The summary of responses¹⁴ to the consultation was published in March 2023 and set out the key themes from feedback received across 225 responses, from a range of electricity market participants and wider stakeholders. The majority of respondents agreed with our proposed vision and objectives for electricity market arrangements (83% and 92% respectively), as well as the case for change (80%). Based on the feedback received, we also decided not to take forward a number of options for further assessment, and to discount some options as standalone mechanisms to deliver our objectives.

This second REMA consultation seeks to set out a clear direction of travel for future GB electricity market arrangements. We are seeking stakeholder views on i) specific proposals and on ii) a short-list of remaining options. In this next phase of the programme, we will consider both the remaining options and the best overall system design, so that REMA delivers a set of reforms that result in a comprehensive and effective set of electricity market arrangements.

¹³ BEIS, 2022, Review of Electricity Market Arrangements – consultation document. Available at: <u>https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements</u>

¹⁴ DESNZ, 2023, Review of Electricity Market Arrangements – summary of responses to consultation. Available at: <u>https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements</u>.

Our approach

How we are assessing REMA options

We have assessed REMA options against **five criteria** which we have updated following stakeholder feedback to our initial consultation and as set out in Powering Up Britain. Together they ensure our objectives of decarbonisation, security of supply and cost-effectiveness are met.

The REMA assessment criteria

- Value for money (previously 'least cost'). 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 the full range of low carbon technologies needed to deliver our objectives, from different types of generation to investment on the demand side. Risks will differ by technology type but should be borne by those best able to manage them.
- Whole-system flexibility. Market design should incentivise market participants of all sizes (both supply and demand) to act flexibly where it is efficient to do so. It should also promote greater coordination across traditional energy system boundaries such as heat and hydrogen, to enable effective optimisation across the system as a whole.
- Adaptability. Market design should be adaptive and responsive to change. It should help ensure delivery of our objectives in a wide range of scenarios and should be robust to uncertainty, for instance regarding commodity prices and technology costs.

Further analysis of the remaining REMA options is explored in the Options Assessment.¹⁵ In Appendix 5 we set out our initial assessment of implications under the Public Sector Equality Duty (PSED) and Environmental Principles Policy Statement (EPPS).

The REMA challenges - current and future challenges for electricity markets

The case for change, as set out in the first REMA consultation, identified key challenges that the future electricity system will face as we move towards a renewables-dominated future – the need for increasing investment, increasing system flexibility, providing efficient locational signals, retaining system operability, and managing price volatility. The case for change also assessed whether our existing market arrangements are likely to meet these future challenges. We concluded that, while existing market arrangements have been effective in delivering the first phase of power sector decarbonisation, we do not consider they will be able to deliver our

¹⁵ DESNZ, 2024, Review of Electricity Market Arrangements: options assessment. Available at: <u>https://assets.publishing.service.gov.uk/media/65eb45ae5b652445f6f21b30/rema-options-assessment.pdf</u>

ambition for a cost-effective, decarbonised and secure electricity system by 2035, nor put us on a pathway to meet our 2050 net zero target.

Stakeholder feedback from the first consultation showed consensus on the need for change, but less consensus on the level and type of change required to address the issues identified. Since then, we have built on the case for change set out in our first consultation, and significantly advanced our work on market failures and issues, as set out in the accompanying Options Assessment,¹⁶ an analytical document which accompanies the consultation. This document aims to provide an overview of the analytical frameworks and bespoke analysis that have been produced to support the policy development process. The Options Assessment describes the market issues and failures and concludes that there remains a strong case for change. The Options Assessment also sets out the next steps for the analysis of the REMA programme and how the analytical framework will be developed in order to move towards appraising options for holistic market design.

Our updated case for change is now based around four key challenges facing future electricity markets, see Table 1 below. The challenges outline the areas where market design must adapt to meet the needs of the decarbonisation transition and a future electricity system based on intermittent renewable generation. Figure 4 on the following page separates the different policy options to be discussed in this consultation for each challenge area.

Challenge 1: Passing through the value of a renewables- based system to consumers	 How best to decouple gas and electricity prices to pass through the benefits of renewables to consumers, and what is the role of marginal pricing within electricity markets? 			
	 How can Corporate Power Purchase Agreements (CPPAs) benefit different consumers and developers of low carbon capacity, and how might this role evolve? 			
	 How do we best incentivise electricity demand reduction from consumers, and what is the role of markets in doing this? 			
Challenge 2: Investing to create a renewables-based system at pace	 How to de-risk investment in renewables while increasing operational risk exposure to deliver lowest overall system cost? 			
Challenge 3: Transitioning away from an unabated gas- based system to a flexible,	 How do we maintain security of supply in a future electricity system dominated by intermittent renewable generation? 			
resilient, decarbonised electricity system	 How do we manage a smooth transition away from unabated gas to low carbon flexible technologies? 			
Challenge 4: Operating and optimising a renewables-based system, cost-effectively	 How do we ensure that efficient price signals are sent in the wholesale market so that whole-system costs are minimised? 			
	 How do we improve mechanisms and markets for balancing the system? 			
	 How do we ensure sufficient liquidity is maintained under future market arrangements? 			
Figure 4: Summary of more detailed proposals to take forward from this second REMA				

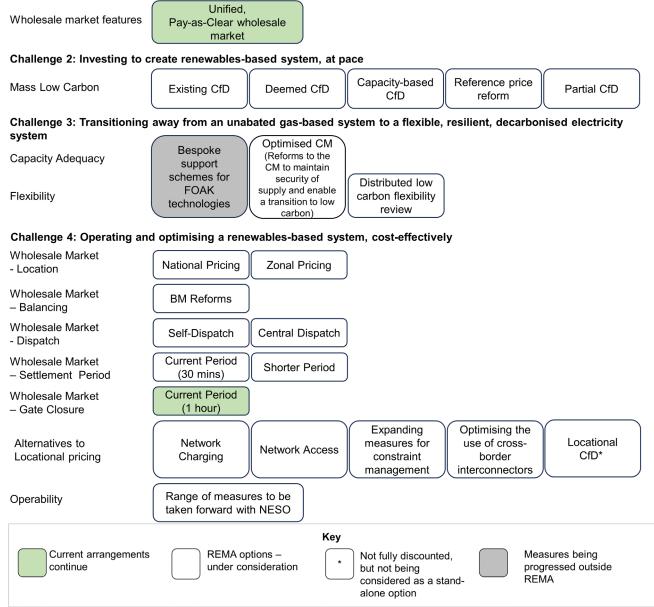
Table 1: The four key challenges underpinning this second REMA consultation

Figure 4: Summary of more detailed proposals to take forward from this second REMA consultation

¹⁶ DESNZ, 2024, Review of Electricity Market Arrangements: options assessment. Available at: <u>https://assets.publishing.service.gov.uk/media/65eb45ae5b652445f6f21b30/rema-options-assessment.pdf</u>

This diagram sets out the options for consideration in this consultation, set against each of the four challenge areas.

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



Interactions between REMA options

This challenge-led approach has helped us significantly narrow down the remaining options to reform electricity markets. However, as set out above, we recognise that electricity market reform is ultimately a whole-system problem, and that in the next phase of REMA we will need to develop a whole-system solution. 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.

In the Options Compatibility and Legacy Arrangements section, we set out an initial assessment of the interactions between policy choices in terms of our future market arrangements. We also set out how we propose to assess the impacts of remaining policy options subject to Legacy Arrangements.

Stakeholder engagement

Electricity markets need to work for everyone – investors, generators, suppliers, other market participants, and consumers, including a diverse range of households, businesses and industries. We have therefore engaged extensively with stakeholders to better understand the impacts of proposals in this consultation. This includes through REMA's Market Participant and End User Forums, and a series of End User Challenge Panels. We also commissioned a variety of external research, reports and analysis, which are published alongside this consultation.¹⁷

We have also actively engaged with the Devolved Administrations and will continue to do so: the REMA programme's scope covers GB, but we have also considered any potential impacts on Northern Ireland as part of our thinking. We are grateful to all those whose contribution has enabled us to significantly narrow down options from the first consultation.

The government will continue to engage with stakeholders throughout the next phase of the REMA programme.

If you would like to be involved in our stakeholder engagement plans going forward, please email <u>remamailbox@energysecurity.gov.uk</u> with the subject line 'Request to participate in future REMA Engagement'.

¹⁷ A list of technical research reports published alongside the consultation can be found here: <u>https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-technical-research-supporting-consultation</u>

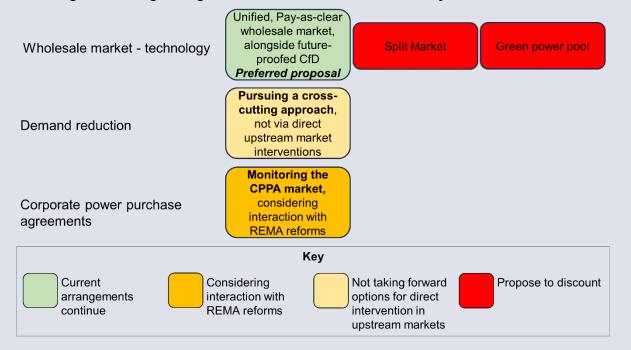
Challenge 1: Passing through the value of a renewables-based system to consumers

Challenge summary

In this challenge, we explore the following questions:

- How best to decouple gas and electricity prices to pass through the benefits of renewables to consumers, and what is the role of marginal pricing within electricity markets?
- How can Corporate Power Purchase Agreements (CPPAs) benefit different consumers and developers of low carbon capacity, and how might this role evolve?
- How do we best incentivise electricity demand reduction from consumers, and what is the role of markets in doing this?

Summary of proposals in this section:



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

Electricity in GB is traded through wholesale markets which, like most commodity markets worldwide, work on the basis of short-run marginal pricing - where the price is set by the most expensive generation asset. This is beneficial in providing price signals for much needed flexible technologies. Our current generation mix means gas generation frequently sets the price - exposing consumers to international price shocks, like those seen recently following the invasion of Ukraine.

Increasing the amounts of domestic renewable generation provides an opportunity to protect consumers from this volatility, by significantly reducing the proportion of time that gas generation sets the price. In addition, the increasing renewable capacity under

schemes such as the current CfD has a further stabilising effect on the price paid by consumers, and that paid to generators.

The first REMA consultation asked for views on whether alternative market structures could better pass through the value of renewables to consumers. These included a Green Power Pool (GPP) and a Split Market, neither of which have been implemented anywhere globally. Both options would involve transformative market restructuring to create separate markets for renewables. A GPP would be likely to be a less intensive intervention, as it would still exist alongside a relatively unchanged wholesale market.

Based on evidence and stakeholder feedback, we intend to discount these alternative options. We identified a number of unresolvable design and deliverability challenges with these options. Furthermore, transformations of this scale would not be in place until the late 2020s at the earliest, by which time any additional benefit compared to current arrangements is likely to be limited because of the pace of the roll-out of renewables.

We therefore propose to maintain a wholesale market unified by technology accompanied by a CfD-type support mechanism as the central driver behind renewable investment and passing through the value of renewables to consumers. In Challenge 2, we are seeking views on how best to future-proof the CfD, to ensure continued deployment of renewables while maintaining value for money for consumers.

Large consumers can take additional steps to insulate themselves from price volatility by purchasing renewable power in current market structures, including through Corporate Power Purchase Agreements (CPPAs). We will continue to monitor the CPPA market and consider how this will interact with REMA reforms.

The first REMA consultation also sought views on the role of markets in incentivising electricity demand reduction, delivered via electrical energy efficiency. We are prioritising a cross-cutting approach to ensuring cost-effective levels of demand reduction are delivered, including potential strengthening of price signals through REMA and retail reforms, and reviewing internal energy efficiency policy appraisal methodologies to ensure electricity demand reduction is properly valued for the whole system benefits it delivers. We have decided not to take forward options for direct intervention in upstream electricity markets, due to the risk of introducing further complexity and distortions into markets, and the risk of poor value for money due to duplication with existing government policies to reduce demand.

The role of marginal pricing in sending market signals

The current role of marginal pricing

The wholesale electricity market, like most commodity markets worldwide, is based on marginal pricing.¹⁸ This means that the cost of the most expensive generation asset needed to meet demand sets the price for the rest of the market, which therefore receive 'inframarginal rent'; the difference between their short-run marginal cost and that of the marginal generator (see Figure 5 below). The marginal price reflects the value of consuming or generating an

¹⁸ Energy in the wholesale market is traded in multiple ways, including on exchanges and bilateral trades. Across all these platforms the expectation of the marginal plant will have a role in price formation.

additional unit of electricity at any given time, providing an efficient and transparent signal for supply and demand decisions. This includes:

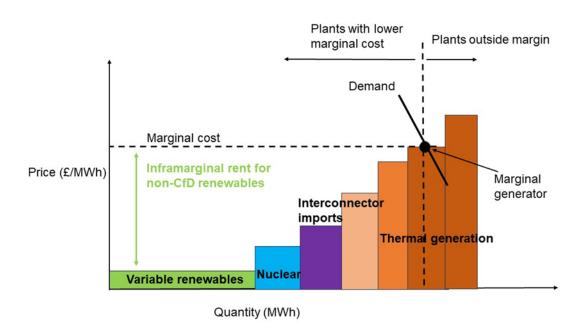
- investment decisions, providing an incentive for innovation and to compete to lower costs; and
- operational decisions, for example, incentivising a battery to charge when prices are low and discharge when they are higher, helping ensure renewable generation is effectively utilised.

Due to gas-fired plants being the price-setting marginal plant most of the time in GB and many other European markets, following Russia's illegal invasion of Ukraine, high international gas prices have increased electricity prices in GB as elsewhere. This has led to higher bills for consumers, and has also increased 'inframarginal rent' and additional profits for those nuclear and renewable generators (whose operating costs did not increase) that are not on fixed price contracts such as the CfD.

Figure 5: Marginal pricing, inframarginal rent, and short and long run marginal costs

Wholesale electricity markets operate based on short-run marginal cost (SRMC) – the cost of producing the next additional unit of electricity. For gas-fired power stations, this will mostly be based on their fuel costs; for renewables such as wind and solar, this short-run marginal cost is low given the low cost associated with producing an additional unit.

'Inframarginal rent' is the difference between a generator's short-run marginal cost and that of the marginal generator, illustrated in the diagram below.



The costs of the current CfD scheme broadly reflect long-run marginal cost (LRMC) – the total cost of producing a unit of electricity, including capital costs associated with construction. For renewables, this is much higher than their short-run marginal cost, as most of their cost is associated with their construction.

The current CfD scheme ensures that, regardless of the market price at which generators sell their power,¹⁹ they receive their 'strike price', protecting them from low wholesale prices. This also protects consumers from high wholesale prices because CfD generators pay back any revenue from power sold at market prices higher than the strike price.

The potential future role of marginal pricing

While gas prices have fallen since the historic highs of 2022, the case for protecting consumers from potential future price fluctuations remains. The CfD already helps to mitigate against this for a growing proportion of assets, as revenues above their 'strike price' are paid back into the scheme - in winter 2022/2023, CfD generators paid an amount back into the scheme equivalent to reducing average annual bills by £18.²⁰ The Electricity Generator Levy was also introduced as a temporary levy (until 2028) on exceptional generation receipts of low carbon generators.²¹

In addition, we need to ensure future market arrangements mitigate against the other manifestation of increasing wholesale market price volatility - increasing 'price cannibalisation', where low marginal cost renewables tending to generate simultaneously leads to wholesale market prices falling during periods of high renewable output, increasing risk to renewable generators – this is discussed further in Challenge 2.

Our current approach, accelerating the roll-out of renewables through a CfD-type support mechanism, will mean:

 Accelerating the deployment of renewables will reduce the proportion of time that unabated gas is setting the price. Figure 6 illustrates the marginal technologies in the modelled DESNZ Higher Demand Scenario. In this scenario, unabated gas falls from being the marginal generator around 80% of the time in 2020, to less than 5% of the time in 2035.²² The 'other' category includes all other technologies, including renewables, interconnectors and low carbon flexible technologies.²³

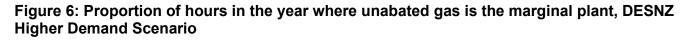
²⁰ £18 household bill savings figure calculated using: CfD savings (<u>https://www.ofgem.gov.uk/publications/latest-energy-price-cap-announced-ofgem</u>) and demand weights for profile class 1 electricity which are provided in 'Annex 2 – wholesale cost allowance methodology v1.14' available at the bottom of this page: https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-january-2023-31-march-2023

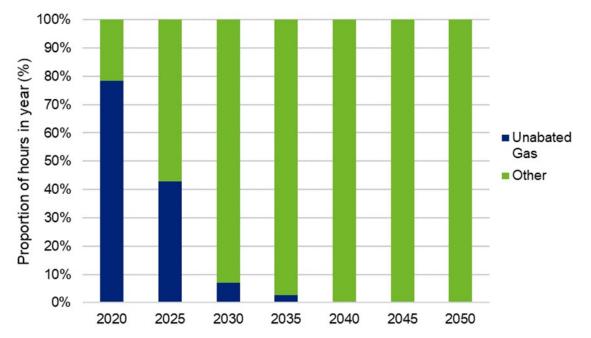
¹⁹ Except if prices are negative – some CfD generators have 'negative pricing rules' in their contracts, which limit or remove top-up payments during periods of negative pricing.

²¹ The levy does not apply to electricity generated under a CfD, nor under any future arrangement for nuclear generation under the RAB model. Furthermore, receipts from new generating stations will be exempted where the substantive decision to proceed with the project was taken on or after 22 November 2023.

²² The frequency with which different technologies are the marginal plant will depend on a variety of scenariodependent and uncertain factors, including the deployment of low carbon technologies, demand level (including role of flexible demand), interconnector flows etc.

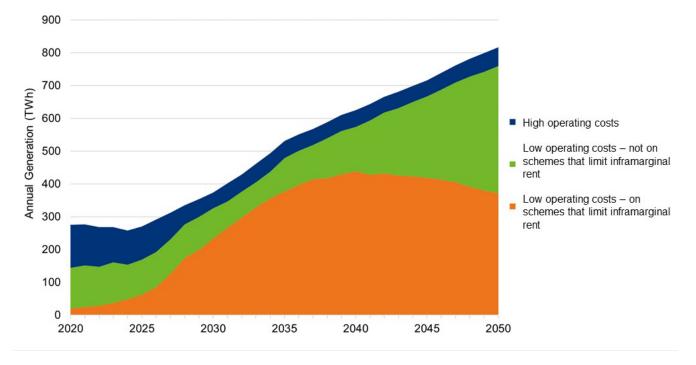
²³ However, there are also indirect relationships between gas prices and electricity prices. When interconnectors are setting the price, the GB system will still be exposed to international gas prices to the extent that gas is setting the price in European markets. Further, some low carbon technologies will still be exposed to international commodity prices. For instance, power CCUS relies on gas as an input fuel, and hydrogen generation could be exposed to gas prices to the extent that the hydrogen price is determined by the cost of gas. However, these periods are likely to be much less frequent than today.





- The low short-run marginal costs of renewables mean that we are therefore likely to observe prolonged periods of low wholesale market prices in future, when renewables are setting the marginal price, together with less frequent periods when prices are higher.
- Furthermore, a CfD-type mechanism can protect consumers during potential periods of high wholesale prices, for an increasing proportion of generation. Figure 7 illustrates that the proportion of generation on schemes which provide a limitation on inframarginal rent (e.g. CfD and Nuclear Regulated Asset Base (RAB)) is expected to increase from around 10% of generation today to around 70% in 2035.²⁴ These schemes decouple gas and electricity prices, because even if marginal prices are high, they limit the pass through to consumer bills; and if marginal prices are lower, they help mitigate against price cannibalisation for generators.

²⁴ While we are considering options through REMA that would change the design of the CfD (discussed further in Challenge 2), these options would still protect consumers from excessive revenue for generators.



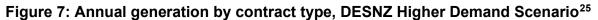


Figure 7 shows: (i) technologies with high operating costs e.g. unabated gas, Power CCUS, Hydrogen to Power; (ii) technologies with low operating costs not on schemes that limit inframarginal rent, e.g. legacy nuclear, Renewable Obligation renewables, merchant renewables; (iii) technologies with low operating costs on schemes that limit inframarginal rent e.g. CfDs and nuclear RAB

Through REMA, we have considered whether this is the best approach, or whether more transformational options (a Split Market or GPP) could offer greater benefits for consumers than accelerating the current approach.

In our first consultation, we sought views on high-level approaches to the options of a GPP and a Split Market.²⁶ As these are novel options which have not been implemented elsewhere, there was uncertainty among stakeholders about their potential risks and benefits compared to an acceleration of the current approach. There was some interest in them being explored further to fully understand these trade-offs.

Through collaboration with stakeholders, we have therefore developed more detailed designs of these market models, to best inform our Options Assessment and enable comparison with accelerating our current approach of deploying renewables through CfD-type mechanisms.

The transformational options: Green Power Pool and Split Market

We considered a wide range of design choices for the more transformational options. This enabled us to determine the most effective design for these potential alternative market pricing

Robinson: <u>https://www.oxfordenergy.org/publications/decarbonised-electricity-system-future-two-market-approach/</u>; the Green Power Pool by Michael Grubb and Paul

Drummond: <u>https://www.ucl.ac.uk/bartlett/sustainable/research-projects/2023/may/reforming-electricity-markets-low-cost-and-low-carbon-power</u>

²⁵ Excludes interconnector flows and storage as these technologies have net negative annual generation.
²⁶ The Split Market by Malcom Keay and David

models and provide exemplar options that enabled different levels of potential intervention to be well understood.²⁷

Table 2 below highlights some (but not all) of the key design features of these models. Further information about these options can be found in Appendix 1.

Design features of transformative options	GPP	Split Market
Both create a separate market for renewables, with prices set at long-run marginal costs, so incorporate capital costs (i.e. incorporating the CfD into the structure of the wholesale market).	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.
Both involve continuation of a short-run marginal pricing 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.

²⁷ To note, the designs presented in this document may therefore diverge from those envisaged in the academic literature.

Some stakeholders had suggested that a benefit of these transformative options could be the 'targeting' of renewable generation at particular sub-sections of consumers, and we have considered the merits of such approaches. We do not consider that such targeting approaches would deliver for the interests of consumers (both domestic and non-domestic), primarily because:

- It is unclear what long-term upside there would be for those targeted compared to the counterfactual that aims for lower prices overall, and where particular groups of consumers are already targeted through existing schemes;²⁸
- As periods and quantities of renewable generation will not necessarily align with the demands of targeted consumers, this complicates design and means additional consumer support would potentially still be required.

More generally, irrespective of whether utilised for targeting or not, there are significant risks associated with the implementation of these novel models. This means that, even after extensive design work, we do not consider them to be deliverable models that successfully pass through the true long-run cost of renewables to consumers. In particular, as electricity is a fungible commodity (electricity generated from a renewable generator has the same properties as electricity generated from a fossil-fuel generator) and can be traded multiple times before it reaches the end-consumer, trading between the two markets (in both models) may result in the lower price in one being driven up towards that of the other section of the market during periods of scarcity. This would likely result in benefits accruing to intermediaries (such as energy traders) rather than consumers, fundamentally undermining the case for these approaches. We do not consider there are deliverable mitigations to this.

The alternative option, of accelerating the roll-out of renewables through a future-proofed CfD scheme, will ensure that a diminishing proportion of renewable and nuclear generation will be paid a marginal price set by gas. The transformative market splitting options would not be expected to further accelerate deployment of renewables, and therefore not deliver any greater consumer savings by reducing the proportion of time that gas-fired generators are the marginal technology. In addition, the delivery risks associated with these transformational options could potentially hinder the deployment of renewables, without any compensating benefits to justify this.

Furthermore, transformations of the scale of market-splitting options would have long implementation times, by the late 2020s at the earliest. They would therefore not be expected to apply to a materially greater proportion of renewable capacity than the alternative or provide a significantly greater degree of price insurance for consumers. A voluntary GPP would not compel existing non-CfD generation to join; while the Split Market could provide such levers, there would be increased deliverability concerns associated with this, and the amount of non-CfD generation that could be incorporated would be diminished by the time it could be implemented.

Ensuring CfDs provide value for money

The use of CfDs as a mitigation tool against high prices needs to continue to be considered carefully in line with value for money considerations.

We considered a scheme to offer CfDs to a significant proportion of existing low carbon generation, known as voluntary CfDs (vCfDs). Although vCfDs could help to insulate

²⁸ Such as the Warm Homes Discount for low-income and vulnerable households, and exemptions from certain components of electricity bills for Energy Intensive Industries.

consumers from potential future price spikes, the contracts could also lock in prices which might not be competitive longer-term as wholesale prices fall. We have therefore concluded that there is not currently a strong case that a vCfD scheme open to a significant proportion of existing low carbon generators would offer value for money and lower consumer bills. The government will therefore not be proceeding with it at this time.

In the longer-term, there may be benefits in options for reforming the CfD which enable more exposure of generators in those schemes to market signals, as explored in Challenge 2. These could remove some of the distortions identified with the CfD and provide system benefits which are passed on to consumers.

Conclusion on marginal pricing and alternatives

Following extensive work to develop and assess the GPP and Split Market options we will no longer continue to consider them in REMA. This is on the basis that they would not deliver benefits for consumers and fail in our assessment against our REMA criteria of deliverability and investor confidence. Instead, we will continue accelerating the deployment of renewables through a future-proofed CfD and maintaining a unified wholesale market for all technologies. This will ensure electricity supply is decarbonised in a cost-effective manner and that the benefits of renewables are efficiently passed through to consumers. We will continue to consider the consumer benefits and distributional impacts of specific options for CfD reform across both domestic and non-domestic/industrial users and as part of our business impacts assessment required as part of the final Impact Assessment.

Corporate Power Purchase Agreements (CPPAs)

While we are no longer considering options which would create a separate market for renewables that consumers can directly interact and contract with, we believe there is a role for consumers in purchasing and helping to drive renewable power within current market structures.²⁹

This includes through Corporate Power Purchase Agreements (CPPAs), which provide another way outside of the CfD for market participants to mitigate risks associated with the growth of renewables. CPPAs are long-term agreements for the purchase of electricity at an agreed price between a developer and corporate counterparty, including businesses and public sector organisations. We consider that CPPAs can benefit both consumers and developers of low carbon generation. They can provide price certainty or a slight discount to market rates directly to the corporate counterparty, while giving new and existing renewables a degree of revenue certainty. Where these agreements demand round-the-clock low carbon power, they can also support investment in storage/flexibility provision. In supporting renewable deployment more generally, they can help increase the time lower-cost assets are price setters and benefit consumers more generally.

The GB CPPA market is small but growing, supporting around 3.5GW of renewable capacity at present, according to BloombergNEF (BNEF),³⁰ making it the 9th largest CPPA market by

²⁹ As outlined in the Introduction, retail markets are being considered through a separate but interlinked programme of reform, and we are carefully considering interactions between REMA and retail markets. There are currently a range of 'green' retail tariffs, on which government has gathered evidence: <u>https://www.gov.uk/government/calls-for-evidence/designing-a-framework-for-transparency-of-carbon-content-in-energy-products-call-for-evidence.</u>

³⁰ Source – BNEF interactive data set on CPPAs, November 2023.

capacity globally. This has largely been driven by corporate interest in power supply decarbonisation and demand for long-term price certainty.

We believe there could be significant further room for growth in this market, given the comparatively low level of capacity supported by CPPAs compared to non-domestic electricity demand, although corporate demand for CPPAs could be tempered in the longer-term by a decarbonising grid. Whilst we did not include explicit consideration of CPPAs in the first REMA consultation, following feedback to that consultation we have considered whether the government could help stimulate the CPPA market to help drive renewable deployment. This led us to consider whether any barriers might have prevented growth of that market.

Our work identified several market barriers. These include:

- **High counterparty risk**: the risk of the organisation buying or selling the electricity defaulting on its payments. Organisations with low credit rating may struggle to secure competitive CPPA terms.
- **High transaction costs**: CPPA deals are often complex and require a high level of commercial and legal expertise, creating a barrier to entry for many organisations that don't have the necessary expertise, increasing transaction costs.
- **Contract length/demand mismatches**: where the generator's required contract length or potential supply exceeds the corporate's needs, leaving the generator with a potentially significant time period without a guaranteed buyer. Developers may require long contract lengths to secure investment whereas organisations may not be able to commit to buying power far in advance.

In addition to understanding market barriers, we also considered options for trying to boost CPPA market growth, such as standardised contracts, a contracts register, exempting CPPA holders from CfD costs, and giving preference to CPPA holders in CfD auctions. However, we believe at this time these are likely to be unworkable, or high risk, or low impact, or address issues the market is already starting to resolve itself (where intervention could hamper innovation).

Therefore, at this comparatively early stage of the CPPA market's evolution, we do not believe there is need for government intervention. We will continue to monitor this growing market, including any barriers to entry and how it interfaces with the CfD. This will support our understanding of how our remaining REMA reform options could impact the CPPA market and ensure that we do not hinder its growth.

Our engagement with industry suggests that most corporates seek deals with new projects. However, we are interested in views and evidence on the role CPPAs could play in supporting existing renewables coming out of support contracts and entering their 'merchant tail'. We are also seeking views on what impact a larger corporate stake in renewables would have on the spread of risk and benefits across consumer groups.

Finally, we encourage respondents to consider current and future CPPA market impacts in their responses to questions across the other sections of this consultation, particularly questions on CfD reform.

Questions:

1. What growth potential do you consider the CPPA market to have? Please consider: how this market is impacted by the barriers we have outlined (or

other barriers), how it might evolve as the grid decarbonises, and how it could be impacted by other REMA options for reforming the CfD and wholesale markets.

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

Renewable Energy Guarantees of Origin (REGOs)

Another means of driving investment in renewables could be through reform of the REGO scheme. The REGO scheme provides certificates to generators to demonstrate electricity has been generated from renewable sources. They can be 'bundled' as part of a CPPA so that organisations can evidence their low carbon power supply. While the sale of REGOs can provide some revenue to generators, they have not historically played a significant role in driving renewable investment decisions.³¹

The government is currently undertaking a broad review of the REGO scheme, exploring how it can further benefit the production of renewable electricity in the UK and wider decarbonisation of the system. We will monitor how the REGO scheme could interact with and complement a future-proofed CfD, and CPPAs, to help drive investment in renewable generation, as well as potentially in low carbon flexible assets.

Demand reduction

Permanent demand reduction delivered through electrical efficiency measures is integral to delivering a fully decarbonised electricity system by 2035, subject to security of supply, delivering both immediate and long-term benefits to the energy system. Over the short-term, reducing demand reduces system costs and contributes to reducing the frequency of periods in which gas sets the marginal price. In the long-term as demand grows from electrification of end-use sectors, ensuring a more moderate demand trajectory is achieved can help to avoid costly overbuild of supply and network assets. This contributes to system resilience and helps to protect the system and consumers from the impact of system stress events.

In the first REMA consultation we sought views on the role of markets in driving investment in electricity demand reduction. Stakeholders were supportive of action on electricity demand reduction generally, citing the need to strengthen incentives, lack of clear signals, and undervaluing of benefits in the market. However, there were mixed views on whether action should be driven via electricity markets or wider energy efficiency policy, given many of the key barriers for electricity demand reduction are not related to electricity market arrangements (e.g. access to finance and information).

Since then, we have identified where certain market failures and cross-cutting policy challenges are potentially leading to electricity demand reduction not being fully valued for the system benefits it provides (see Options Assessment). We have continued engaging with stakeholders to further understand the potential impact of evolving government policy on incentives for electricity demand reduction, as well as new electricity market-based

³¹ A 2021 Call for Evidence from DESNZ on 'Designing a framework for transparency of carbon content in energy products' sought views on the role of REGO certificates in financing and commercial decision making. Almost all respondents agreed that REGOs have historically been too cheap to influence long-term investment decisions. However, it should be noted the prices of REGOs have increased in recent years.

approaches. Our planned approach to promoting electricity demand reduction is summarised below.

Addressing cross-cutting departmental challenges to value the whole system benefits of electricity demand reduction: We have identified that government policy appraisal methodologies may not properly value the whole system benefits of electricity demand reduction. This gap is particularly acute for large scale policy interventions, which have the potential to impact the size and composition of the power system, and for interventions that are specifically designed to impact peak demand or support security of supply objectives. As a result, addressing potential flaws in the way that the government values demand reduction could have a significant impact on improving the case for strengthening policies that impact electricity demand. We commit, therefore, to reviewing our methodology and process for valuing electricity demand reduction during 2024.

Sharper price signals: Across both REMA and our parallel programme of work to reform retail energy markets, options are being considered and progressed to sharpen price signals for electricity demand reduction. Market-Wide-Half-Hourly settlement, which is an industry-led change programme overseen by Ofgem, will sharpen temporal signals for electricity demand reduction, while REMA is considering the benefit of introducing shorter settlement periods. REMA is also considering how to send more effective locational signals as set out under Challenge 4; depending on the options taken forward and their implementation (in terms of the extent to which consumers are exposed to these signals), these could sharpen locational signals for demand reduction.

Strengthening existing departmental energy efficiency policies: The government is continuing to build on its existing portfolio of energy efficiency policies and is currently investing £6.6 billion over this parliament with a further £6 billion committed between 2025-2028 to support domestic and non-domestic consumers to reduce their energy use.

- Improving the energy efficiency of households: The government has committed significant funding for various capital schemes like the Local Authority Delivery Scheme, the Home Upgrade Grant, Boiler Upgrade Scheme, and the Social Housing Decarbonisation Fund to deliver energy efficiency measures. In addition, last year we launched the Great British Insulation Scheme to help families to install improvements such as insulation and we are dedicating a further £400m for families across England to improve their homes, through a new grant in 2025. For those not eligible for direct government support, we are incentivising lenders to provide more attractive loan offers through our Green Home Finance Accelerator and expanding our consumer advice with a new online tool and phone service dedicated to retrofit advice. We also recently set out plans for all new homes and buildings to be zero-carbon ready from 2025.
- Supporting businesses to reduce their energy demand: The government has committed to a £185m extension to the Industrial Energy Transformation Fund (IETF). This includes £175m of capital budget from the £6 billion announced at the 2022 Autumn Statement. This means that the IETF will provide up to £500 million for energy efficiency and low carbon technologies across the 3 phases. We have also announced a new six-year Climate Change Agreements Scheme, with reduced rates on the Climate Change Levy now due to end in March 2033. The Energy Savings Opportunity Scheme, where large businesses must undertake energy audits and are encouraged to make improvements in the way they use energy, has been strengthened. We have also launched a pilot energy assessment and grant scheme to deliver subsidised energy assessments and grant funding for energy efficiency measures to SMEs in the West Midlands and are now considering options for future policy.

Unlocking retail market innovation: Reforms to retail markets and exposing suppliers to sharper signals could drive more innovative retail service offers for consumers. Some innovative offers could support the financing of energy efficiency improvements through bundled contracts, such as through 'energy as a service' offers, which could help consumers to reduce the up-front cost of installing energy efficiency measures. The government conducted a Call for Evidence in 2023, 'Towards a more innovative energy retail market,' that examined issues around innovative supply offers such as bundled contracts. A response to the Call for Evidence was published on 23 February 2024, setting out next steps for retail market reform.

Market-based models for demand reduction: The first REMA consultation identified three broad categories of market-based mechanisms for directly funding electricity demand reduction, and we have further reviewed the case for their introduction:

- Competition in an existing market (e.g. the Capacity Market)
- Creation of a new bespoke market (either an auction or pay-for-performance model)
- Obligations on utilities (e.g. retail suppliers or Distribution Network Operators)

While we recognise that there have been some successes with funding electricity demand reduction through electricity markets in different contexts internationally, we have opted to discount these options in the GB context. In doing so, we have also taken account of the previous Electricity Demand Reduction pilot within the GB Capacity Market (which ran from 2014 to 2017),³² and the range of other demand reduction policies already in place in GB. It is our view that 'upstream' (i.e. non-retail) markets are not the right place to intervene given the potential complexity of integrating electricity demand reduction into the Capacity Market and the distortive market impacts of any new bespoke revenue stream which is not technology neutral. There would also be concerns around the potential upfront cost impact on consumers' bills of new interventions.

We also have concerns about the potential value for money of further interventions to support demand reduction through upstream electricity markets, and how additionality could be demonstrated beyond our existing efforts to expand and strengthen downstream policies for consumers and ongoing reforms to retail markets. There is a risk that a market intervention could fund measures that would have been deployed without additional funding, or that could have been incentivised through interventions which do not require billpayer or government funding such as minimum energy efficiency standards. Many of the barriers to demand reduction deployment also stem from outside upstream markets, such as access to finance and information or long-term certainty for supply chains to build. Therefore, we have concluded that these are best addressed outside of upstream electricity markets through wider government energy efficiency policy (further detail on our rationale is covered in the Options Assessment).

Question:

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

³² DESNZ and BEIS, 2019, Guidance: Electricity Demand Reduction Pilot. Available at: <u>https://www.gov.uk/guidance/electricity-demand-reduction-pilot</u>

Conclusions and next steps

This section has detailed that we will be:

- Proceeding with the rapid rollout of renewable generation via a CfD-type scheme (see Challenge 2), alongside maintaining a wholesale market based on short-run marginal pricing.
- Not continuing to consider transformational Split Market and GPP options.
- Considering the potential role of CPPAs and how they might grow and evolve in future to support further renewable and low carbon deployment.
- Strengthening our cross-cutting approach to ensuring cost-effective levels of electricity demand reduction are delivered.

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

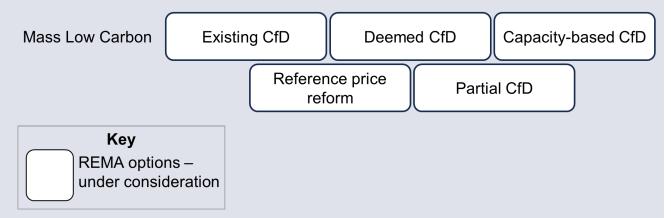
Challenge summary

In this challenge, we explore the following question:

- How to de-risk investment in renewables while increasing operational risk exposure to deliver lowest overall system cost?

Summary of proposals in this section:

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



Significant investment in new renewable generation will be needed over the coming years if we are to deliver our 2035 objective for a fully decarbonised electricity system, subject to security of supply. This section commits to a future-proofed CfD-type scheme as the government's main mechanism for supporting investment in renewable electricity generation. This means making sure the CfD continues to provide investor confidence and deliver value for consumers as our electricity market evolves and decarbonises. It acknowledges the success to date of the current CfDs, as well as the growing limitations of the current CfD approach.

The CfD scheme needs to be fit for a future system where an even greater portion of our electricity comes from renewable, weather-dependent technologies, often located far from demand. The challenge of using the CfD to meet our future renewable investment ambitions while delivering the most value for money across the electricity system can be split into three questions:

- 1. How do we significantly scale up renewables investment?
- 2. How do we maximise CfD assets' responsiveness to system needs?
- 3. What is the best way for the CfD to distribute risk across electricity market participants?

This section considers a range of ways we can build on the strong foundations of the current scheme in response to these challenges. This includes retaining key features

such as competitive auctions to minimise costs to consumers, the award of long-term contracts with LCCC as the counterparty to provide investment confidence, and a mechanism to protect consumers against high wholesale electricity prices. It also includes potential reforms to the CfD payment structure, so that payments are delinked from a generator's metered output through either deemed payments or a capacity payment model, alongside a range of supplementary reform options which aim to increase exposure to market signals, including a partial CfD.

Ensuring the CfD is fit for the future

The CfD scheme, the main government mechanism for supporting investment in large-scale renewable electricity generation, has been vital to increasing investor confidence and helping us meet our deployment targets, whilst helping keep costs low.

Since its introduction in 2014, it has successfully supported a rapid increase in renewable investment, allocating contracts to over 30GW³³ of renewable capacity. Generation from its first three allocation rounds saved consumers an estimated £3bn up to 2020 in comparison with supporting the same projects under the Renewables Obligation (RO).³⁴

What is the CfD?

The Contract for Difference (CfD) is a long-term contractual arrangement between a renewable electricity generator and the Low Carbon Contracts Company (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 wholesale 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 (AR4) so that no difference payment is paid for any period when the day-ahead price is negative.

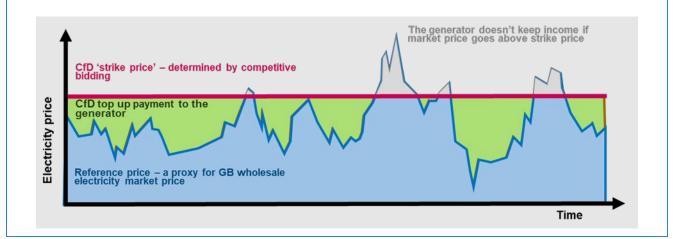
The difference payments protect investors from periods of low wholesale market prices, which would otherwise have to be priced into investment decisions. Conversely, consumers are also protected from periods of high prices as generators are levied to repay money to the LCCC if market reference prices 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 renewable 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

³³ Including projects that did not sign, or failed, their milestone requirements.

³⁴ BEIS, 2020, Evaluation of the Contracts for Difference Scheme, page 13, available at: <u>https://assets.publishing.service.gov.uk/media/627e3f76e90e0721b01ea526/CfD_evaluation_phase_2_final_repo</u>rt.pdf.

we have received so far suggests a CfD-type scheme will continue to be the best tool to drive renewables investment.



The CfD scheme has evolved over time – building on lessons learned – and will need to continue doing so in response to the investment challenges of today. The scheme's sixth Allocation Round (AR6) opens in March 2024. Government recently published the core parameters of this auction, including the round's pot structure and administrative strike prices, reflecting on updated evidence on the significant cost increases the sector faces.³⁵ The move to annual auctions has already allowed government to incorporate learnings from Allocation Round five (AR5) into AR6 (see core parameters in footnote 36), and these parameters are intended to maintain strong investment in GB's renewable sector, securing vital capacity whilst protecting consumer bills through competitive allocation. Allocation Round 7 (AR7) will build on this learning, continuing to adapt the current scheme to address issues both now and in the medium-term. DESNZ released an AR7 consultation on 11 January 2024.³⁶

REMA is taking a longer-term view, looking ahead to the challenges of the 2030s, and how the CfD will need to adapt to meet the changing needs of our decarbonising system. This includes considering how the scheme might need to change alongside other REMA reform decisions, for example on wholesale market arrangements, and what the wider system impacts are of having a significant proportion of GB generation capacity on CfDs. To date, new renewables capacity brought forward by the CfD has been displacing fossil fuel capacity from our electricity system. As a result, the proportion of GB electricity from renewables has risen from 15% to more than 40% over the period 2013-2022.³⁷ The evidence we have gathered thus far suggests we will need more profound reform to address the distortions caused by current CfD design (see below on ensuring CfD assets respond to market needs) and ensure risk is allocated in a manner which delivers lowest system cost as the generation mix continues to evolve.

As highlighted in Challenge 1, we believe the CfD has an important role to play in our market in all scenarios. However, it will need to evolve further if it is to respond effectively to three important questions:

³⁶ DESNZ, 2024, Proposed amendments to Contracts for Difference for Allocation Round 7 and future rounds, available at: <u>https://www.gov.uk/government/consultations/proposed-amendments-to-contracts-for-difference-for-allocation-round-7-and-future-rounds</u>

³⁷ DESNZ 2023, Digest of UK Energy Statistics (DUKES): electricity, Table 5.6.B, available at: https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

³⁵ DESNZ, 2023, Contracts for Difference (CfD) Allocation Round 6: core parameters, available at: <u>https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-6-core-parameters</u>

How do we significantly scale up renewable investment?

We estimate that we will need 140-174GW³⁸ of renewable capacity in 2035 to meet our Carbon Budget 6 power sector decarbonisation commitments, up from approximately 56GW³⁹ in 2023. This requires a 150% to 200% increase in installed capacity.

Delivering this level of investment represents a huge challenge, even before accounting for the increased risks that investors will likely face under the status quo as the system decarbonises. In particular, as the amount of renewable generation on the system increases over time, we expect an increase in the number of periods when electricity supply is likely to exceed demand (e.g. on sunny/windy days when supply will be very high). Renewable generators may, therefore, struggle to find a buyer for their power more often, with knock-on impacts on CfD payments (due to the link between metered output and CfD payments). The current CfD does not protect against this increasing 'volume risk', and so may not be as effective in the future at supporting investment as it has been in the past.

Through REMA, we need to ensure a future-proofed CfD achieves a high level of investor confidence to deliver large scale investment in renewables at low cost to the consumer.

How do we maximise CfD assets' responsiveness to system needs?

This huge scale-up of investment will mean that CfD-backed intermittent generation with low running costs will account for the majority of the GB electricity market by 2035. There are some elements of the current CfD design that cause costly problems for the day-to-day management of the electricity system and that will only amplify as more CfD assets come online, as set out below. A full list of these behavioural distortions is in Table 3. We will also need to consider the possible impacts of having an increasing proportion of assets on CfDs on the proper functioning of the wholesale market itself, including effective price formation so that prices accurately reflect system needs.

Some of these issues have been partly addressed or may be resolved through design changes that have already been implemented or are under consideration. For example, new guidance⁴⁰ which clarifies that CfD generators co-located with storage receive CfD payments that are settled at the point and time of generation should go some way to removing barriers to the co-location of renewable assets with storage. Also, the negative pricing rule was updated so that, for assets granted a CfD in Allocation Rounds from AR4 onwards, the scheme makes no support payments when the day-ahead market price (the CfD reference price) is negative.⁴¹ This disincentivises generation when prices are negative in the day-ahead market and therefore aligns generator behaviour with day-ahead market needs. However, this rule has also introduced a price threshold that distorts market operation and will reduce revenue certainty for generators with CfDs as negative pricing periods become more frequent.

³⁸ 2035 figure based the 2022 net zero lower and net zero higher scenarios consistent with meeting CB6 from the Department's power sector model, the Dynamic dispatch Model. Published in Annex O of the Energy and emissions projections, May 2023, available at: <u>https://www.gov.uk/government/collections/energy-and-emissions-projections</u>.

³⁹ DESNZ, 2023, Energy Trends December 2023. Available at: <u>https://www.gov.uk/government/statistics/energy-trends-section-6-renewables</u>.

⁴⁰ Low Carbon Contracts Company, 2023, CfD Co-Location Generator Guidance, available at:

https://www.lowcarboncontracts.uk/resources/guidance-and-publications/cfd-co-location-generator-guidance/ ⁴¹ More information available at: <u>https://www.gov.uk/government/collections/contracts-for-difference-cfd-allocation-</u> round-4

A range of investment and operational distortions remain:

Operational signals: the current CfD design incentivises maximum generation output whenever the day-ahead reference price is above zero, which although often rational at a project level, can create various dispatch inefficiencies and higher system costs. These include encouraging generation even when the wholesale market price is below their Short Run Marginal Cost (SRMC), day-ahead prices strongly influencing intra-day operational and trading decisions, CfD-backed assets distorting the merit order in the Balancing Mechanism by trying to recoup lost subsidy in the event of a turn down action, and dissuasion from providing ancillary services that require reduced metered output. The CfD can also create price thresholds, where assets turn on/off at the same time, creating expensive cliff-edge effects often referred to as 'herding behaviour', as well as introducing barriers for forward trading, which may impact suppliers' ability to hedge.

Investment signals: the CfD auction awards contracts based on a 'strike price', which reflects factors including project costs and expected future revenues. The fixed strike price impacts project characteristic signals, as developers invest in technologies that maximise output, rather than maximise overall system benefit. For example, forgoing investment in additional equipment to enable provision of ancillary services.

Through REMA, we need to ensure a future-proofed CfD maximises the potential of renewable assets to respond to market signals, rather than distorting behaviours and decision making. Different distortions associated with the CfD may occur in future market scenarios, however Table 3 focusses on the CfD in the current market. The possible CfD reforms in this section seek to address some or all of the operational distortions, as well as project characteristic investment distortions. Locational investment distortions are considered in Challenge 4. More work is needed to understand how asset managers and developers would respond to market signals if these distortions were removed.

Type of signal	Signal	Description	How current CfD design impacts signal
Operational	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 intra-day prices, during all periods of non-negative day-ahead IMRP. ⁴²	
		Distortive During network constraints CfD generators will require turn down payments in the BM equal to the foregone difference payment.	
			Distortive

Table 3: Outline of the CfD's distortive impacts

⁴² Intermittent Market Reference Price (IMRP) is a proxy figure for the wholesale price of a unit of electricity. Within the CfD it is used to determine the level of top-up or payback payments for intermittent generators and is calculated for each hour using the day-ahead weighted average of EPEX & N2EX markets.

			Generators are incentivised to bid in the wholesale market in the same way ('herding'), leading to potentially expensive cliff edges when price becomes negative due to the negative pricing rule, making it difficult for the system operators to manage the system.
	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 mean 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 value of power versus the system value of the 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. ⁴³ 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 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. However, this distortive impact is

⁴³ Unpredictability in earnings related to variation in the difference between i) reference wholesale market price and ii) average capture price.

		weak relative to the locational investment signals and distortions present in wider market arrangements (discussed in Challenge 4).
Project characteristic	Which technology, what size? Should a project co-locate with storage? Should you invest in equipment to provide ancillary services?	Potentially distortive The CfD system incentivises developers to maximise their potential to generate at all 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.

What is the best way for the CfD to distribute risk across market participants?

The extent to which the CfD should in future shield investors from, or expose them to, specific risks is a fundamental part of our assessment (noting that decisions to shield/expose investors from certain risks will have consequences for other market participants, such as suppliers and consumers). Further discussion on how REMA is considering the allocation of risks and incentives amongst market participants is set out in the introduction. Well allocated risk – i.e. risk allocated to the parties that are best suited to manage it – should lead to system-wide benefits and a more efficient system overall, as well as reducing the investment and operational distortions set out in this section.

There is inevitably potential for tension between (a) de-risking investment and (b) increasing assets' exposure to operational risks to maximise their responsiveness to system needs. Through REMA we are aiming to arrive at the solutions which best achieve lower overall system costs, taking account of both cost of capital and system operational costs, which will necessitate striking a balance between these two objectives.

Our assessment of CfD reforms primarily focusses on the impact upon price risk and volume risk (explained below and in Table 4). The CfD reform options under consideration offer different ways of providing revenue certainty (to support investor confidence and keep the cost of capital low) and controlling the degree of exposure to both price and volume risk (to maximise CfD assets' responsiveness to system needs). Through REMA, we will need to consider how our overall market design – both wholesale market reforms and CfD reforms acting in conjunction – can distribute risks in a manner which delivers lowest system cost, whilst also de-risking and driving investment in the renewables we need.

Price risk

When the CfD was established, protecting assets from price risk, i.e. shielding them from electricity price fluctuations, was identified as the best way to provide investors with sufficient revenue certainty that they could have confidence in making a reasonable return on their investment. The CfD does this by providing generators with a fixed price for electricity, linked to their output. This was considered key to unlocking investment in renewables and reducing the cost of capital in an emerging market. The cost of providing this price certainty to investors is

ultimately borne by consumers, via the CfD levies imposed on suppliers. That said, consumers have also benefited through increased protection against spikes in wholesale prices. Over the winter of 2022/23, when wholesale electricity prices were higher, the CfD delivered the equivalent of an £18 saving on a typical annual household bill.

Since the CfD's inception, intermittent renewables have become an established part of our electricity system, and as wholesale prices have risen, we have seen the emergence of new 'stacked revenue' models, where developers operate part CfD and part merchant/CPPA, accepting greater price risk. The extent to which developers will continue to pursue this path is unclear, however. There are signs that a challenging global macroeconomic environment could be making financing renewables harder. Renewables-led price cannibalisation, increasing wholesale price volatility and more frequent periods of negative pricing could also strengthen renewables developers' desire for price risk protection.

In considering how REMA manages price risk, we will also need to account for impacts on consumers and possible trade-offs between the degree of price certainty and the level of support payments.

Volume risk

This risk for generators is the uncertainty around how much electricity their asset will be able to sell. This is largely driven either by weather uncertainty or the inability to secure an offtaker.⁴⁴ As mentioned in the investment section, it is likely that in future electricity supply may exceed demand more often, leading to more frequent zero or negative pricing periods.⁴⁵ The CfD exaggerates this issue by incentivising renewables to generate even when they are not required to meet demand (see earlier detail on operational distortions).

Increasing volume risk will increase uncertainty of future revenues. This could translate to higher CfD strike prices as assets need to cover total project costs across a smaller amount of generation, and higher cost of capital due to increased revenue uncertainty.

Risk	Description		Current CfD Design
	Policy driven electricity price risk	Risk that a policy change results in a change in electricity prices (including carbon price).	Fully protected
	Other electricity price risk	Risk that electricity prices are lower than expected for market reasons.	Fully protected
Price Risk	Basis Risk	Risk that generators cannot achieve the reference wholesale price due to variability in output profile.	Almost full protection

Table 4: Current CfD Risk Allocation

⁴⁴ This risk may be mitigated by the CfD arrangements for an Offtaker of Last Resort.

⁴⁵ The frequency that supply exceeds demand in future will also depend on wider market design and the scale of flexible assets in the system.

	Locational price risk	Risk investors are exposed to changes in the value of the locational electricity price signal i.e. in the case of locational pricing, the spread between the local and system average price.	No locational price risk in current market (Transmission Network Use of System (TNUoS) charges provides some locational cost risk).
Volume Risk	Policy driven demand risk	Risk that the demand for electricity 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 of the network not being able to physically accommodate their power.	Generators not exposed to locational volume risk in current market.

Questions:

- 4. Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address.
- 5. Assuming the CfD distortions we have identified are removed, and renewable assets are exposed to the full range of market signals/risks (similar to fully merchant assets), how far would assets alter their behaviour in practice?

Scope of CfD reform

The first REMA consultation presented a wide range of conceptual ideas for reforming our approach to supporting investment in renewables. This included transformational changes to the wholesale market (e.g. Split Market and Green Power Pool), transitioning to completely new schemes (e.g. equivalent firm power auctions), or keeping the existing CfD either 'as is' or with reforms.

Through the REMA assessment process, as detailed in the Introduction, we have narrowed and refined the scope of options so that all remaining options under consideration represent specific reforms to the CfD scheme as opposed to its replacement (see Figures 2 and 8). This process drew upon analysis from the first consultation, a commissioned report undertaken by Frontier Economics and Cornwall Insights on market signals and investor behaviour, and extensive engagement with industry experts and external stakeholders.⁴⁶

Identifying the fundamental issues and key benefits of different options has enabled us to target specific CfD design choices (e.g. payment structure, reference price calculation), analysing how they could contribute to the future success of the scheme by alleviating system challenges or allocating risk more efficiently.

We do not put forward a preferred version of the future CfD at this stage. This is because determining the best combination of CfD reforms will depend on decisions made elsewhere in REMA, especially wholesale market reform decisions, such as locational pricing. These design choices ensure we retain a degree of flexibility to amend the CfD in a manner which integrates with wider REMA reforms to deliver our objectives.

Figure 8: How 'Mass Low Carbon' reform options have progressed since the first consultation



⁴⁶ Frontier Economics and Cornwall Insight, 2023, Market Signals and Renewable Investment Behaviour. Available at: <u>https://assets.publishing.service.gov.uk/media/65e5a4372f2b3bbc587cd78c/6-frontier-cornwall-insights-market-signals-renewable-investment-behaviour.pdf</u>

Discounted options

In addition to the options discounted immediately following the first consultation, and the transformational options discounted in Challenge 1, our assessment process has led us to rule out the two following changes to the CfD:

CfD with a strike price range: Under this option, the CfD strike price would fluctuate within a set range, exposing assets to market signals within that boundary. The REMA assessment concluded that this option would put more price risk onto CfD assets – leading to the highest notional strike prices of all options being considered – without providing comparable benefits, scoring it very low on the REMA criteria of value for money and investor confidence.

A revenue cap and floor (RCF): Under this option, CfD assets would be protected from periods of low prices with a minimum guaranteed revenue (floor) and consumers would be protected from periods of high prices with a revenue share mechanism (above the cap). Through our assessment process we identified several critical issues with this model. In particular, the model affords significant opportunities for 'gaming', i.e. there is potential for generators to manipulate or reduce the revenues reported under the RCF, resulting in a greater payment being received if revenues are below the floor or reducing the required repayment amount if above the cap. Our assessment also identified a significant risk that this model could distort operational behaviour, i.e. if generators anticipated earning revenues below the floor over the reconciliation period, they would lose the incentive to generate. The likelihood of renewable assets earning revenues below the floor is potentially high given the issue of 'price cannibalisation'.

More detail on reasons for discounting these options is in the accompanying Options Assessment. Challenge 3 also provides an assessment of the RCF for supporting investment in low carbon flexible assets.

Remaining CfD reform options

We are seeking views on the remaining CfD reform options. In particular, we are interested in views on how the options can help us meet our future renewable investment challenges, how they perform against the REMA assessment criteria and how they interact with the remaining wholesale market reforms.

The CfD currently supports both intermittent and non-intermittent technologies.⁴⁷ We acknowledge many of the future challenges with the current CfD design will be due to the increased proportion of intermittent technologies on the system. That said, we will need to consider how REMA reforms to the CfD will work for the full range of technologies that will be supported by the scheme. We are interested in evidence and views on how different reform options could impact different technologies and whether there are specific design challenges we should be aware of when reforming the CfD, noting that we keep technology eligibility under constant review, and it may be subject to change in future rounds.

⁴⁷ List of non-intermittent technologies from AR5 core parameters: Energy from Waste with CHP, Hydro (>5MW and <50MW), Landfill Gas, Sewage Gas, Advanced Conversion Technologies, Anaerobic Digestion (>5MW), Dedicated Biomass with CHP, Geothermal.

Ongoing CfD reforms

The CfD is continuously evolving to meet the challenges faced by the sector. The overall focus for AR6 is on maintaining and increasing investor confidence by setting appropriate parameters to secure enough capacity whilst minimising consumer costs.

The government has also recently consulted on potential CfD reforms for both AR7 (scheduled to open in 2025) and beyond. While not part of the REMA programme, these interventions could support REMA aims. Possible amendments to the scheme include:

- Expanding the scope of the CfD to support the repowering of existing eligible projects at the end of their operating life. This would help support REMA's objective of scaling up renewable capacity but could increase the proportion of generation capacity on current CfD terms, adding to the scale of market distortions.
- Introducing new hybrid metering arrangements for CfD assets, aiming to improve renewable site flexibility and grid operability, which may help alleviate some of the operational distortions currently seen within the CfD, as well as facilitate the Challenge 3 low carbon flexibility goals. This proposal would uncouple the CfD from the Balancing and Settlement Code at certain points and could reduce the barriers that currently prevent some innovative, co-located generation models from being viable.

These potential changes – together with other wider market reforms – could help address some of the challenges outlined at the start of this section, although there will likely be some issues not addressed by these changes. Respondents should bear these in mind when considering the CfD reform options below. Whether or not we decide to reform the CfD's payment structure or keep it as it is and rely on other reforms to address the identified challenges will be determined ultimately through the work we do in the next phase of REMA.

Question:

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

Payment structure reform: Delinking CfD payments

One of the ways we could address some of the distortions associated with the existing CfD is breaking the link between an asset's actual metered generation and subsidy payment/ clawback amounts. There are two main ways we are considering adapting the CfD's payment structure to do this: **deemed payments** or a **capacity payment**, both of which pay for a renewable asset's potential to generate.

Both options should resolve the operational distortions associated with the current CfD (Table 3), since assets should be incentivised to participate in whichever electricity market(s) give the greatest returns (e.g. wholesale market vs. ancillary service provision). Assets should also be incentivised to reduce their output when the market is over-supplied, since if they are generating when the market price is less than their short run marginal cost, they will be worse off than if they had decided to stop generating. However, a deemed CfD may not resolve forward trading inefficiencies because a reference price would remain central to how it calculates payments. A capacity-based CfD may also use a reference price under certain designs (e.g. gainshare mechanism), albeit this should have less of an impact on trading incentives.

Both options would – if implemented – only apply to CfDs awarded in future auctions. They would both provide investor certainty over a significant proportion of their revenue, with assets free to pursue additional revenue opportunities in all relevant markets based on the system value of their individual plant. These additional revenue opportunities exist in the deemed CfD model when assets participate in markets/services where the price is higher than the wholesale market reference price, as they will retain the extra revenue. Under a capacity-based CfD, assets can retain additional revenue from participating in the wholesale market (up to an administratively set strike price, when a gainshare mechanism kicks in), or through participating in other markets/services. Generators would therefore operate on merchant terms under both options, optimising their trading and operational strategies to maximise revenues across markets.

Deeming CfD payments

Deeming is the process of determining the maximum amount of generation an asset could in theory produce at any point in time reflecting 'live' conditions (e.g. weather). To accurately determine this, the government would need to establish a deeming methodology. Subsidy difference payments could then be determined by this deemed output, meaning their actual generation and activity in the market would be separate from subsidy payments. Aside from replacing metered output with deemed output, this model would retain most of the existing CfD design, including the auction process.

CfDs with deemed generation continue to protect assets from price risk (like the current CfD), while also potentially adding in protection from certain types of volume risk not covered by the current CfD. In particular, assets operating with a deemed CfD could have the negative price rule removed as they would no longer be incentivised to generate when prices are below their Short Run Marginal Cost. The increased revenue certainty from the removal of the negative pricing rule could be reflected in a reduction in financing costs and lower CfD strike prices, while still protecting consumers from periods of high prices. However, the negative pricing rule also protects consumers at times when the national supply of electricity exceeds demand, so any decision to remove the negative pricing rule would need to have a clear overall benefit for consumers. This means that the potential reduction in financing costs and lower CfD strike prices would need to offset a higher volume of CfD payments that consumers would be exposed to. These decisions need to be considered against what the best overall distribution of risks across a renewables-dominated system is, and therefore what design features would overall be best value for consumers.

The extent to which deeming would protect assets from these risks is dependent on the detailed design and implementation choices we make, and where we determine that different risks should sit. Deeming also introduces an element of profile risk for assets, as if their actual output is higher/lower than deemed output they will retain more/less revenue than their strike price suggests they should.

Any approach based on deeming carries a risk of gaming and overcompensation, as the circumstances in which assets would be paid, and the level of payment they would receive, is no longer based on an asset's actual output, which is simple to measure and verify. Assets would be able to profit at the expense of consumers if the deeming methodology was not accurate or fair, if they were able to manipulate the circumstances in which they would or would not receive payment, or if they were able to manipulate the level of deemed output calculated.

Certain design choices could reduce these risks, although more work is needed to test how far they can be fully mitigated. This includes identifying and establishing a robust deeming

methodology and considering the potential for interchanging the use of metered output and deemed output under different market price conditions. The LCCC will have a critical role in accurately assessing deemed output levels and protecting against gaming risks. It is likely that the ESO/NESO will also play an important role in this process.

All the design choices for a deemed CfD will be made taking account of future wholesale market arrangements. We have already considered the compatibility of deeming with a range of wholesale market reform options, some of which rely on exposing assets to more price and/or volume risk. The deeming model has the potential to be flexible in these different scenarios, but adopting different variations will add complexity to the design and may add considerable implementation challenges, which will require further testing with industry stakeholders. It is also possible to phase the introduction of deeming into the current CfD design by only using deemed output in limited situations.

The final assessment of the deemed CfD option will depend on how well it can be adapted to fit with wider reforms and how confident we are that we can resolve the risks and challenges associated with this option through robust design and implementation. More analysis is also needed to determine whether this model has the potential to deliver the best value for money for the consumer, as on the one hand it should deliver lower system costs, but it also has the potential for a higher volume of support payments as it allows assets to be paid in full even when generation is curtailed.

The deeming methodology

Achieving the benefits associated with this option is dependent on having a deeming methodology which is accurate, consistent and that protects against gaming risks. Further work needs to be done with industry experts on the specifics of how deeming could work in practice for individual technologies.

We are considering a range of possible deeming methodologies and are seeking views and evidence on which are the most accurate and fair for all market participants.

Option 1: An accredited third party would determine deemed output by combining site-specific weather and asset data in a standard process set by government. Asset owners would need to install specified on-site meteorological equipment. This option should be robust and limit opportunities for manipulation but is likely to cost asset owners more than other options.

Option 2: Similar to Option 1, asset owners would collect site-specific data to input into the deeming methodology set by government.⁴⁸ However, the data collection and calculation of deemed output would be undertaken by the asset owner rather than an accredited third party. This would be simpler and cheaper to implement, but potentially more vulnerable to manipulation.

Option 3: Government-created/appointed theoretical or actual reference generators, potentially in different geographical locations for different technologies, would provide deemed generation volumes. This option fully separates the deeming process from asset owners so would be very hard to manipulate, however it will be more difficult to ensure accuracy for individual assets increasing basis risk.

⁴⁸ For wind assets, this should largely follow the existing process for determining the power available signal, noting that the power available signal in its current form is not accurate enough for the purposes of deeming. For more information on how power available is used now: <u>https://www.nationalgrideso.com/news/power-available-phase-2-further-unlocks-potential-variable-generation-provide-balancing</u>

Option 4: If we limit the scope of deeming generation to only when assets are participating in approved ancillary services that require them to turn down their output, then subsidy payments could be based upon metered output for all other periods. Deemed output during periods of ancillary service provision could be calculated accurately utilising data from the ESO. This would allow assets to retain additional revenue from participating in ancillary service markets when prices in those markets are above the wholesale market reference price. This option would minimise potential market disruption by retaining metered output in most cases, however it would only address one of the distortions associated with the current CfD.

Monitoring, evaluation and enforcement of deeming would depend on the chosen option and would ultimately be evaluated by the LCCC. This would be subject to the LCCC having the necessary powers, ability and resources to accurately evaluate assets' deemed output level. This can only be determined once we have a more detailed deemed CfD design.

Any deeming approach would become more complex if there were any circumstances in which we might not want assets to be paid – as set out in Table 5. For example, in a scenario in which the wholesale market has been reformed to introduce locational signals through zonal pricing, if we do not want to pay deemed CfD assets when there is more supply than is needed to meet demand within a zone, the existing negative pricing rule may not be effective in passing through the locational signal to CfD assets. This is because assets would be paid according to their deemed output rather than their actual output and so may be incentivised to self-curtail their output before wholesale prices in their zone go negative – leading to a situation where prices never actually go negative, or are only negative for short periods, with assets essentially insulated against locational signals. Solutions would likely lead to further complexity.

Deemed generation variations

The deemed CfD model can be varied to distribute risk across the system differently. This will be an important component of ensuring any deeming model complements decisions made across REMA. A summary of these potential variations, and their intended effect on risk distribution, is in the table below:

Risk exposure aim	Deemed CfD variation	Description
Decrease volume risk for assets	Remove negative pricing rule	Removing the negative pricing rule for deemed CfD assets would protect them from volume risk. We think this is possible as under a deemed CfD the bidding behaviour distortions associated with the current design are removed. This would likely increase the volume of CfD payments that assets receive and, if strike prices did not reduce by an offsetting amount, could increase consumer costs overall.

Table 5: Deemed CfD risk allocation

	Deem only when prices are negative	This variation would maintain the link between metered output and CfD payments when prices are positive. CfD payments would only use deemed output when the reference price is negative, potentially with limits on the number / percentage of negative pricing periods. This would not address all the operational distortions associated with the current CfD, but it would reduce volume risk for assets with minimal disruption to the overall CfD scheme. The effect on overall consumer costs would depend on how much strike prices are reduced with this variation, as outlined above.
Decrease profile risk for assets	Deem only below the strike price	This variation would maintain the link between metered output and CfD payments when the reference price is above an asset's strike price. This would remove the risk of assets having to pay back more revenue to the LCCC than they gain through the wholesale market because, for example, they were unable to generate, or the deemed output was overestimated. This would add an extra process for the LCCC, who would have to alter their calculations based on the wholesale market price.
	'Turn off' deeming when the asset is unavailable to generate	This would 'turn off' deeming in certain situations where assets cannot generate. For example, if wind turbines are frozen but wind conditions are strong. This would introduce further design complexities to the deemed CfD model.
Increase locational volume risk for assets	Aligning deeming with removal of firm access rights (separate wholesale market reform under consideration in Challenge 4)	A deemed CfD could insulate assets from locational signals introduced via the removal of firm access rights. We are considering variations to the deemed CfD which could reintroduce this signal (if desired). This would require direct communication between the ESO and the LCCC. Further

	work is ongoing on the implications of removing firm access rights as this is a cross-cutting market issue.
Administratively remove payment from periods of constraint	Under this variation, the ESO would communicate to the LCCC when and where network constraints are occurring, or where they would have occurred had deemed CfD assets not all self-curtailed, (which would require this to be calculated administratively utilising data on the deemed output for all assets in an area). Once this information is gathered, the subsidy payment for assets in the identified area would be reduced, introducing locational volume risk.

Deemed generation variations for different wholesale market designs

Locational pricing

The deemed generation model may need further variations if implemented alongside a move to a locational wholesale market (under consideration in Challenge 4). This is because a basic deeming model would likely shield generators from the greater volume risk otherwise associated with locational wholesale market arrangements, particularly where assets locate in highly constrained areas where they might regularly have to turn down their power supply. This would dampen the locational signals that locational pricing intends to send. The following deemed generation variations could help pass through locational risks if that is considered necessary to deliver overall lowest system cost:

- Deeming with a system average price: Assets sell their generation at the price in their zone, but by default the CfD subsidy calculation would use a system average reference price. This introduces locational price risk as assets in areas with lower prices will receive relatively lower revenues than assets in areas of higher prices.
- Deeming with addition of locational low pricing rule: Adjustment of the negative pricing rule whereby assets no longer receive CfD payments when the reference price in their zone falls below a certain threshold, for example £5/MWh. This threshold would be met more often in areas which see more network constraints, re-introducing volume risk and sending a locational signal to encourage assets to locate in areas which see low prices less often. This variation could add new distortions into the market as assets would look to adjust their behaviour to prevent prices going below the price cut-off level.
- Deeming with revenue from 'constraint periods' reduced: The ESO communicates to the LCCC when and where network constraints are occurring, or where they would have occurred had deemed CfD assets not all self-curtailed. Once this information is gathered, the subsidy payment for assets in the identified zone would be reduced, re-introducing

locational volume risk. This would be complex to design and implement and would place a considerable importance on the ESO's curtailment modelling.

Central dispatch

Depending on its design, moving to central dispatch could address a number of the dispatch distortions the current CfD creates. This would reduce the benefit of introducing deeming into the CfD mechanism. However, there could be value in introducing a variation of deeming as central dispatch would likely increase volume risk for assets. This variation would introduce deeming under set conditions when assets are not selected to run, decreasing volume risk for generators but potentially increasing overall costs for consumers. More detailed assessments will be possible with more detailed central dispatch designs and clarity on wholesale market reforms.

Capacity-based CfD

Given the uncertainties set out above regarding aspects of the deemed CfD option (in particular potential gaming risks and complexity), we have developed an additional option which alters the CfD payment structure to be 'capacity-based'.

Unlike the current or deemed CfDs, a capacity-based CfD would not calculate difference payments to generators based on market or generation conditions. Instead, the model would pay an asset, once operational, a regular, fixed amount based on installed renewable capacity (£/MW), independent of the asset's market activity (although potentially adjusted by an 'availability factor' – see Appendix 2 for further detail). Generators would therefore operate on merchant terms, optimising their trading and operational strategies to maximise revenues across markets.

This model would expose generators to both volume and price risk on a day-to-day basis, but also provide them with a degree of revenue certainty to support investment decisions. Doing so should provide similar operational and investment benefits to the deemed CfD, although we would expect the market signals driving those benefits to be even stronger under this model with less complexity and scope for gaming.

When bidding for a capacity-based CfD in competitive auctions, we would expect developers to reflect anticipated market revenues in the level of capacity payment sought. However, given the significant uncertainty around market revenues (due to the growing volume and price risks in the market), it is possible that developers may seek to de-risk investment decisions through a high capacity payment.

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. This mechanism could be based on current CfD arrangements. For example, if wholesale market prices exceeded an administratively set strike price (£/MWh) the asset would be obliged to payback some or all the difference (based on metered output). The strength of these arrangements to protect consumers against wholesale market price volatility, relative to other CfD options, is dependent on decisions on the level of the strike price and what proportion of the difference is paid back.

A capacity-based CfD would distribute risk differently to our other CfD reform options and could better support the theoretical benefits case for zonal pricing by fully enabling price and volume risk exposure in that scenario. These benefits need to be weighed against the potential for increased cost of capital. We will also need to consider whether and how capacity payments reflect project location and the potential for reduced output over time due to wear and tear. The

final assessment of the capacity-based CfD will depend on how well it fits with wider REMA reforms and if it offers value for money relative to other CfD reform options – on the one hand it could deliver lower system costs, but it also has the potential for higher support payments.

More detail on the design of this model can be found in Appendix 2.

Questions:

- 7. What specific gaming risks, if any, do you see in the deemed generation model, and do any of the deeming methodologies/variations alter those gaming risks? Please provide supporting reasoning.
- 8. Under a capacity-based CfD, what factors do you think will influence auction bidding behaviour? In particular, please consider the extent to which developers will be able to reflect anticipated revenues from other markets in their capacity-based CfD bid.
- 9. Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q25 on which actors are best placed to manage the different risks?
- 10. Do you have a preference for either the deemed CfD or the capacity-based CfD model? Please consider any particular merits or risks of both models.

Supplementary reform options

There are other reforms to the CfD that could address some of the operational and investment distortions associated with the current design, without changing the payment structure. These could be implemented in parallel with, or instead of, payment structure reforms.

Partial CfD payments

Under a partial CfD, only a percentage of an asset's total capacity would be covered by a CfD for all new projects. In other words, a developer would not be able to bid to cover all its capacity under the CfD. This proportion would be fixed for the duration of the CfD contract and announced in advance of any auction. The electricity generated by the part of the site covered by the CfD would be subject to top up and clawback payments from the LCCC equalling the difference between the strike price and the reference price. The other part of the site would not receive top-up/claw-back payments and so would operate on a merchant basis. The intention would be to meter different parts of the site separately for the purposes of CfD settlement, though we acknowledge that there are some challenges to this design, such as ensuring the merchant part of the site builds out as planned. We are open to alternative arrangements if they can be shown to deliver greater benefits.

Further work is required to understand if and how this option would change behaviour in practice: whether it would result in the two parts of the site responding differently to market signals. If this is the case, this option could create system benefits, including reducing the opportunity cost associated with operating flexibly that normally exists within the CfD.

We believe there could be appetite for this type of CfD model in industry, as we see that some developers are already adding merchant generation onto the same site as CfD generation as part of a stacked revenue model.

This option should be compatible with other REMA reform options, including locational wholesale market interventions, and could be based on either the current CfD or deemed CfD.

This option would put more price risk onto generators than the current CfD, which could increase cost of capital and lead to higher notional strike prices, although this increase would apply to a reduced volume of renewable power and bring with it an additional volume of merchant generation. The risk of very high wholesale prices feeding through to consumers also increases because less generation is subject to clawbacks. Developers could seek to sign PPAs with corporate customers or energy suppliers for the merchant portion of their volume, however, which could help limit consumer exposure to price volatility. Further work is needed to assess the extent of these risks and how they compare to the potential system benefits of reduced operational and investment distortions for the non-CfD portion of the site. A key consideration will be what proportion of the site should be covered by the CfD as this will impact the balance of risks and benefits of this option.

CfD reference price reform

In the first REMA consultation, we set out the potential to increase price exposure of intermittent renewable CfD assets through changes to the Intermittent Market Reference Price (IMRP). At present, the day-ahead IMRP reinforces incentives for renewable assets to sell all their generation into the day-ahead market to minimise basis risk. This has contributed towards sheltering assets from wider market dispatch signals and the removal of forward trading incentives that assets may otherwise have had under merchant conditions.

We have considered a range of reference price options and are considering two new options that would change the risk profile of CfD-backed assets and broaden exposure to market signals, prompting generators to be more responsive to market needs:

1. **Hybrid reference price**: Where a portion would be set using a longer reference price, anywhere from a month ahead to a season ahead, whilst the remaining portion would be set at the day-ahead price. The key element to this option is the percentage split between the day-ahead market and other markets. This will form the focus of the next stage of development.

This option could remove barriers to forward trading and increase incentives for generators to hedge a portion of their generation ahead of time, whilst also maintaining the benefits of the day-ahead reference price. More detail on liquidity challenges can be found in Challenge 4. However, it could also disadvantage smaller assets that may not have the collateral to participate in forward trades or the resource and expertise required to make more advanced trading decisions.

2. **Extended reference price**: Which would be calculated in a similar way to the existing reference price but using a weighted volume average of more market price data, up to one month prior to delivery.

This would increase market exposure over a short timeframe for generators, which could incentivise more efficient use of their asset such as taking advantage of arbitrage between low and high wholesale prices or providing alternative services. However, we are uncertain as to whether this would change generator behaviour in practice, and it is unclear whether this would encourage more forward trading.

Changing the reference price could complement other CfD reforms such as the deemed CfD or partial CfD. The capacity-based CfD may also utilise a reference price – for the purpose of

implementing a gainshare mechanism – in which case these reference price options will also be a consideration.

Overall, the potential benefits of changing the reference price need to be considered against both the potential increase in the costs of capital that exposing assets to more basis risk may result in, and the potential that assets consistently get paid more than their strike price at the expense of consumers. We will also need to consider interactions with other indexes used across markets, such as that used to decide the price cap for suppliers. We welcome further views and evidence on this.

Small-scale renewables

The first REMA consultation sought views on how electricity markets could better value the low carbon and wider system benefits of small-scale distributed renewables. Small-scale renewable projects could play a key role in the UK meeting its carbon budgets and net zero targets. They also offer societal benefits such as engaging local communities in renewable energy projects, tackling fuel poverty by reducing energy bills and creating new jobs.

Respondents suggested a range of ways government could reform markets to support smallscale deployment. One suggestion was to open the CfD to more small-scale deployment, with many projects currently locked out by minimum capacity requirements. Following stakeholder engagement, we decided that small-scale generators would struggle to compete with larger projects for support through the CfD. Opening the CfD to more sub-5MW generators might also complicate budget setting. Small-scale generators we spoke to said that the administrative burden would also put off many from entering.

Some respondents also pointed to the potential of local markets (e.g. reorient the wholesale market around local, distribution-level markets to more effectively utilise the distribution network) in driving small-scale renewables. This is not an option we believe has sufficient merit to be progressed. We say more on this in Challenge 4. Similarly, some commented on the need to reform the Smart Export Guarantee (SEG). Ofgem reports annually on the range, nature and uptake of tariffs offered by suppliers in response to their SEG obligations. We will continue to review this to monitor whether the market is delivering an effective range of options for small exporters. To date, the market has responded positively, with a range of SEG tariffs, demonstrating the fact that market-led approaches to delivering small-scale renewables can be successful.

Where we do see some potential for existing markets to increase small-scale deployment is through PPAs, as set out in Challenge 1. According to BNEF, most corporate PPAs in the UK are for projects above 5MW.⁴⁹ We would welcome views on whether and how the PPA market could evolve alongside existing mechanisms, such as the SEG, and other REMA reforms, in growing small-scale renewables.

Questions:

- 11. Do you see any particular merits or risks with a partial payment CfD?
- 12. Do you see any particular merits or risks with the reforms to the CfD reference price we have outlined? Please consider how far the two reforms we have

⁴⁹ Available at <u>https://about.bnef.com/</u> and accurate as of November 2023

outlined might affect both liquidity in forward markets and basis risk for developers.

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

Conclusions and next steps

In this section:

- We have committed to a future-proofed CfD-type scheme as the government's main mechanism for supporting investment in renewable electricity generation.
- We have set out three challenges we need to overcome to future-proof the CfD in a way that delivers the best value for money across the electricity system. These are:
 - o Scale-up renewables investment to meet our decarbonisation targets;
 - o Allow electricity generators to respond to market needs; and
 - o Allocate risk where it is most manageable in the system.
- We are looking for evidence and views on further reform options for the CfD, focussing on how they can help us achieve our three challenges, how they perform against the REMA assessment criteria and how compatible they are with remaining wholesale market reforms.
- We do not put forward a preferred version of the CfD at this stage because determining the best combination of the above reforms will need to be taken in conjunction with decisions made elsewhere in REMA. In other words, the best CfD design will depend on what the electricity market it operates in looks like.

We will also consider Allocation Round 7 consultation responses when reviewing responses to this consultation.

In terms of next steps, the next phase of REMA will shift to a narrower, deeper assessment of the remaining CfD reform options, with the purpose of identifying a preferred option based on robust cost-benefit analysis. We are aiming to complete this 'policy' stage of the programme by mid-2025. It is likely that we will move to implement the chosen CfD reform option/s as quickly as possible after policy decisions (likely from Allocation Round 9) to avoid locking in an increasing proportion of renewable generation on current CfD terms. Although it is possible that some CfD reforms may be more suitable to be implemented alongside any wider wholesale market reform at a later date.

The chosen CfD mechanism will have to work seamlessly with future wholesale market arrangements, both to deliver overall REMA objectives plus respond to the specific challenges identified earlier in this section with respect to investment in renewables. The next phase of REMA will, therefore, include consideration of how the different CfD options interact with potential reforms under consideration in Challenge 4. A particular focus will be on how CfD and wholesale market reforms might act in combination to differently distribute risks, benefits, and costs across market participants and technologies. We will need to take final decisions on

preferred CfD and wholesale market reforms together to achieve overall lowest system costs and lowest cost for consumers.

We will aim to provide as much clarity as possible on the chosen end-to-end implementation pathway in the next phase of REMA to ensure investors/developers have a clear view of what changes will be made and when to the CfD and wholesale market.

We recognise that implementation of wholesale market reforms, in particular locational pricing, could have significant implications for existing CfD assets and those looking to participate in upcoming Allocation Rounds. Challenge 4 considers this in more detail.

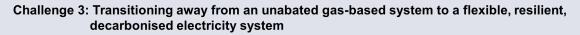
Challenge 3: Transitioning away from an unabated gas-based system to a flexible, resilient, decarbonised electricity system

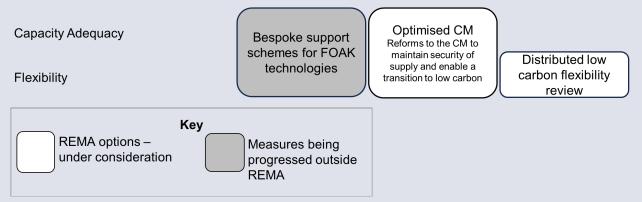
Challenge summary

In this challenge, we explore the following questions:

- How do we maintain security of supply in a future electricity system dominated by intermittent renewable generation?
- How do we manage a smooth transition away from unabated gas to low carbon flexible technologies?

Summary of proposals in this section:





Maintaining a secure electricity supply throughout the transition to our future renewablesdominated system is essential. The roll-out of intermittent renewable generation (such as wind or solar) brings benefits for our security of supply, by reducing our dependence on volatile global gas markets.⁵⁰ However, it also presents new challenges, particularly in ensuring that alternative sources of flexible capacity continue to be available at times when renewable generation is lower.

Flexibility, defined as the ability to shift the consumption or generation of electricity in time or location, is essential for the functioning of our energy system. Whilst we have been very successful at reducing the role of fossil fuel generation across the electricity system, currently the vast majority of system flexibility is provided by unabated gas generation.

The transition to a decarbonised power system will significantly increase the need for low carbon sources of flexibility to replace unabated gas generation and ensure we can continue to balance supply and demand at all times in a net zero world. To ensure

⁵⁰ DESNZ, 2023, Digest of UK Energy Statistics (DUKES): electricity. Chapter 5, Table 5.6, available at: Table 5.6.B, available at: <u>https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes</u>

security of supply in 2035, we expect to need 55GW of short-duration flexibility and between 30 to 50GW of long-duration flexibility. The government's aim is for as much of this long-duration capacity as possible to be low carbon.

Whilst low carbon flexible technologies are developing, unabated gas will continue to play a key role in maintaining a secure electricity supply, particularly during peaks in demand and when renewable generation is low. As existing generation capacity expires in the coming years, investment in new, long-duration flexible capacity will be needed to replace expiring plants and ensure security of electricity supply. In the short run we expect that some new build gas generation capacity will be required to enable this transition.

The decarbonisation of unabated gas generation will be key to reaching our ambitious Sixth Carbon Budget (CB6) and net zero targets alongside the rapid deployment of new build low carbon flexible technologies and services. These include Power CCUS, Hydrogen to Power (H2P), electricity storage, interconnectors, and demand-side response (DSR).

Future market design must manage and incentivise the transition to low carbon flexibility, maintaining security of supply in a complex and changing energy system. We are developing clear decarbonisation pathways for unabated gas generation to ensure a smooth glide path to a fully decarbonised electricity system by 2035, subject to security of supply.

The first REMA consultation set out that the current market framework does not maximise the potential for the full range of flexible technologies to deploy or operate optimally. It sought views on a wide range of options for incentivising low carbon flexibility and capacity adequacy.

Following further assessment, the government intends to retain the CM as our capacity adequacy mechanism and this section sets out a review of options to evolve it to meet future capacity adequacy challenges in the most effective, efficient and timely way.

Government proposes to introduce a minimum procurement target ('minima'), into the CM (which we are calling an 'Optimised CM') as an enduring mechanism for supporting investment and deployment of low carbon flexible technologies. This would introduce changes to the auction design which will ensure it procures the optimal technology mix to support all future needs of a fully decarbonised electricity system, and to better reflect the role and value of low carbon flexible technologies in the CM. We are seeking views on the proposal to reform the CM to better support low carbon flexibility through the Optimised CM design.

Alongside REMA reforms, the government is addressing barriers faced by specific low carbon long-duration flexible technologies, including developing bespoke mechanisms to provide protection and support where needed, and ensuring power projects have access to necessary low carbon infrastructure, such as hydrogen and CO₂ transport and storage networks. To ensure clear decarbonisation pathways for our remaining unabated gas generation, greater hydrogen and CO₂ capacity would need to be available in future. To this effect, the government recently published consultations on potential mechanisms to support Hydrogen to Power and Long Duration Electricity Storage (LDES).⁵¹ Whilst

⁵¹ DESNZ, 2023, Hydrogen to power: market intervention need and design. Available at: <u>https://www.gov.uk/government/consultations/hydrogen-to-power-market-intervention-need-and-design</u> DESNZ, 2024, Long duration electricity storage: proposals to enable investment. Available at: <u>https://www.gov.uk/government/consultations/long-duration-electricity-storage-proposals-to-enable-investment</u>

bespoke mechanisms may be needed to initiate deployment of these projects, in the long-term, the Optimised CM should be the primary scheme for supporting the deployment of a competitive mix of low carbon flexibility. This will ensure that costs to the consumer are minimised. Government will seek to promote competition between projects and technologies wherever appropriate in order to deliver a cost-effective system overall.

Delivering flexibility and security of supply

Ensuring a secure and reliable energy supply is essential. We face new challenges as our electricity system decarbonises and as more of our economy is electrified.

Our main tool to ensure a secure electricity supply is the CM, which was introduced in 2014 as part of the EMR programme. This was against a backdrop of older plants reaching the end of their lifespan with insufficient new plants projected to come online to replace the lost capacity. It was designed to ensure a reliable and secure electricity supply by encouraging investment in new capacity. The CM has performed well against its objectives and has helped to maintain security of supply during this period at least-cost to consumers. The ESO's assessment shows winter margins⁵² have stayed well within the legislated reliability standard since the CM's introduction. Since its introduction in 2014⁵³ the CM has secured around 19GW of new build de-rated capacity.

However, the nature of the security of supply challenge is changing as we move towards a renewables-dominated system. For example, in the past, system stress events⁵⁴ were largely expected to be driven by events and outages which were independent of each other. In the future, the nature of system stress is likely to become more complex and dependent on more volatile weather patterns, with events likely being more supply-driven (for example, extended periods of low wind generation during cold winter days). Our electricity system is also becoming more interconnected with other countries, which should increase our resilience overall but also changes the nature of the security of supply challenges we face.

The electricity system will therefore need to adapt to evolving challenges and effectively manage both short-duration and seasonal variations. Reliable electricity supply and system resilience must be maintained throughout the transition to a fully decarbonised electricity system by ensuring capacity adequacy and operability. We will therefore need a system with technologies and market arrangements that can meet all of these challenges.

The transition to a fully decarbonised electricity system will dramatically increase the need for low carbon flexibility to balance supply and demand at all times and maintain the security and stability of the electricity system – a role historically played by unabated fossil fuelled generators. It is a key priority for government to accelerate the deployment of all low carbon flexible technologies at pace in order to meet our power sector decarbonisation ambitions and net zero targets. Low carbon forms of short-duration flexibility such as batteries and DSR will reduce the need for thermal generation by flattening the demand profile and helping deal with within day fluctuations in renewable output. However, there will also be a need for low carbon long-duration flexibility (e.g. Power CCUS, H2P, and LDES) as a replacement for unabated gas for the residual and longer periods where renewable generation is not able to meet

⁵² National Grid ESO, 2023, Winter Outlook 23/24. Available at: <u>https://www.nationalgrideso.com/research-and-publications/winter-outlook</u>

⁵³ Electricity Market Reform Delivery Body, Electricity Capacity Reports and Security of Supply documents. Available at: <u>https://www.emrdeliverybody.com/CM/Capacity.aspx</u>

⁵⁴ Periods when the spare capacity of electricity on the system used to balance supply and demand is reducing.

demand. In 2021, there was about 60GW of flexibility on the system, 20GW of which were low carbon assets.⁵⁵

We are therefore updating our expectations of the amount of flexibility we will need on our future electricity system, to ensure security of supply and keep costs as low as possible for consumers. We hope that this further clarity will provide additional confidence for investors in these essential technologies. For short-duration flexibility, e.g. batteries and DSR, a range of internal and external models estimate that the GB electricity system could require up to 55GW of capacity by 2035. For long-duration flexibility (i.e. H2P, Power CCUS, unabated gas, and LDES), a range of external models estimate that the GB electricity system could require between 30 and 50GW of capacity by 2035; the government's aim is for as much of this long-duration capacity as possible to be low carbon.

Improving energy efficiency will also ensure security of supply by reducing the demand profile. In addition, interconnectors will play a key role in the GB electricity market by offering system flexibility to support security of supply, affordability, and decarbonisation through the trading of electricity with connected countries.

Existing investment and operational signals following reforms to current market arrangements have had a positive impact in bringing forward some low carbon flexible capacity (primarily short-duration battery storage and interconnectors). However, as we outlined in the first REMA consultation, the current market framework does not maximise the potential for the full range of flexible technologies to deploy or operate flexibly, which has the potential to result in increased security of supply risks and/or increased emissions. Low carbon flexibility faces a range of challenges:

- A lack of sufficiently granular time and location-based operational signals to incentivise the flexible and efficient operation of assets in response to system needs e.g. during sustained periods of system stress.
- Higher investment costs from technologies being First of a Kind (FOAK) and with uncertain future operating profiles, and low carbon flexibility not being sufficiently valued in current market arrangement.
- A reliance on infrastructure that is not yet in place (i.e. a hydrogen network and CO₂ transportation and storage).

To address these challenges, we need to ensure that the electricity market is designed in a way that sends:

- Sharper operational signals demonstrating when and where valuable flexibility is needed, and to which these technologies can respond; and
- sufficient investment signals to bring forward technologies and services of all sizes and types.

Through Challenge 3, we propose a package of reforms to ensure that there is sufficient investment in all forms of low carbon flexibility at the pace and scale required, whilst maintaining security of supply through the transition to a fully decarbonised electricity system.

⁵⁵ National Grid ESO, 2022, Future Energy Scenarios. Available at: <u>https://www.nationalgrideso.com/document/263876/download.</u>

Challenge 4 explores options which would create sharper operational signals that reflect system needs and incentivise flexible operation at different times and across locations.

Ensuring a secure and reliable low carbon system

Future of Capacity Adequacy

The previous REMA consultation set out options for delivering capacity adequacy as we transition towards a decarbonised power sector. **Following consideration, the government intends to retain an Optimised Capacity Market as our capacity adequacy mechanism**. The CM is a well-established and proven mechanism, which has delivered against its security of supply objectives. In addition, our analysis of alternative capacity mechanisms, both from theory and practice, concluded that none of these options offer better value for money or investment potential for the challenges of low carbon flexible capacity investment and the unabated gas transition. We have set out our assessment of the options and our reasons for discounting them in the Options Assessment that has been published alongside this consultation. A high-level summary of our rationale can also be found in the below Discounted options section of this section.

Reforming the Capacity Market (Optimised CM)

The majority of capacity bought through the current technology-neutral CM to date has been fossil fuel-based generation. Although this capacity will continue to have a role to play while we transition to a fully decarbonised electricity system, and we expect that a limited amount of additional new gas generation will be needed in the short run to replace existing capacity as it expires, change is required to better align the CM with our decarbonisation ambitions and the changing nature of the energy system.

In the first consultation we included proposals on ways to optimise the CM to support and complement our decarbonisation objectives through auction design reform. The consultation identified how the auction could be designed to better reward low carbon flexible technologies to address future capacity adequacy challenges. This could be achieved by valuing desirable characteristics such as low carbon capacity and/or the flexibility capabilities needed to meet key system requirements, such as:

- 'response time' the speed at which assets can respond to signals; and
- 'sustained response' the ability to sustain capacity over a prolonged period of time.

The three auction design options we have explored are:

- **Split auction** where technologies with different characteristics (i.e. high and low carbon capacity) are procured separately through two or more auction cycles, which run sequentially with procurement targets set independently for each.
- Single auction with multiple clearing prices (using 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. We have further explored how this could be achieved by setting a minimum procurement target (otherwise known as minima) for desirable characteristics.

• **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 to better reward their contribution.

The majority of responses to the first consultation were strongly supportive of optimising the CM but there were different views as to which of the auction designs was most appropriate, which highlighted the need for further work to understand the implications for competition, liquidity and the complexity of the auction. Since then, we have further developed all three options, and undertaken a dedicated research project,⁵⁶ which considered the auction designs against international practices and reviewed potential impacts on auction dynamics. The research found that in theory all three options could be designed to better incentivise low carbon flexible technologies, but with varying benefits and risks.

Regarding multipliers, the research concluded that, despite the advantages associated with retaining a single auction, the design remains subject to volume uncertainty, i.e. even a relatively high multiplier may not lead to procuring higher volumes of low carbon flexible capacity. Given this persistent volume risk, we have found that multipliers do not meet our low carbon flexibility objective, and they further carry the risk of potentially leading to suboptimal results in terms of cost-effectiveness. **We are therefore discounting the option of introducing multipliers.**

The research results for both the split auction and the single auction with minima revealed they carry similar benefits and risks. However, splitting the auction introduces risks in terms of liquidity for the low carbon pot in the earlier years (while certain new low carbon flexible technologies are scaling up), and low liquidity in the high carbon pot in later years as the amount of unabated capacity on the system reduces. An additional risk with the split auction design is the additional challenge and complexity of setting two separate capacity targets and running two separate auctions, which would be more resource and time intensive. The single auction with minima likely has two practical advantages over the split auction – potential administrative simplicity and minimising the risk of gaming during the auction process. Another potential benefit is that the use of minima allows for more flexibility over how the minima is set and how it affects the overall auction parameters and design. We are therefore taking forward the single auction with multiple clearing prices auction design, with a focus on introducing a minimum procurement target for desirable characteristics (i.e. minima).

Further work is underway to develop how minima should be defined and set (i.e. to procure low carbon capacity and/or key flexibility capabilities). We are working on the interactions between minima, wider auction set-up, auction parameters and short-term CM policy changes to devise an enduring package of changes that will ensure the Optimised CM can continue to deliver a secure, decarbonised and cost-effective electricity system.

Questions

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

⁵⁶ Baringa Partners, 2023, Assessing the deployment potential of flexible capacity in Great Britain – an Interim Report. Available at: <u>https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf</u>

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

As well as reforming the auction design, we are working to ensure that the CM is able to reflect the changing nature of security of supply through:

- Auction targets: We will work with ESO to give greater clarity on auction targets for years beyond the four-year ahead (T-4) Delivery Years, building on the Panel of Technical Experts⁵⁷ recommendations and giving investors a longer time to plan and government a greater insight into future security and capacity.
- **Strengthening CM rules:** We will keep the CM rules under ongoing review to protect consumers and bear down on costs so that billpayers are protected during the transition to a fully decarbonised electricity system, including to address any risks around market power.
- **Considering further changes:** In the immediate term, we will consider whether any further changes to the CM are required to mitigate risks to security of supply. If required, we will consult on further CM changes in due course.
- Ensuring the reliability standard is fit for purpose: We are exploring the changing nature of future stress events and potential alternative approaches and metrics to the current standard. The GB Reliability Standard metric 3 hours Loss of Load Expectation (LOLE), defined in hours/year represents the average length of time within the year for which loss of load is tolerated to occur. It was developed to deal with relatively uniform problems with uncorrelated generation outages, with expected loss of load instances addressed with incremental flexible capacity. With the changing nature of the power system, we expect the nature of future stress events to change, which requires reconsideration of the wider capacity adequacy framework.

We have started investigating possible changes required to ensure our framework remains robust, reliant, and resilient. As a first stage we have commissioned a research project to explore whether LOLE remains an appropriate measure as well as potential alternative metrics.⁵⁸

The findings suggest that future stress events will likely become much more complex with a more comprehensive risk profile. What we are likely to see is:

- more correlated weather-driven reductions in supply, with increased risk of extended periods of system stress and larger reductions in output;
- plant outages no longer being a defining factor in system stress; and
- increased instances where system stress likely occurs outside of peak demand periods.

The study concludes that there may be a case to include a combination of metrics in the Reliability Standard. We will undertake further policy development into the case for change,

⁵⁷Panel of Technical Experts, 2023, Report on National Grid ESO Electricity Capacity Report 2023. Available at: <u>https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1171340/panel-of-technical-experts-2023-report.pdf</u>

⁵⁸ LPC Delta and Frontier Economics, 2023, Exploring Reliability Standard Metrics in a Net Zero Transition. Available at: <u>https://assets.publishing.service.gov.uk/media/65e3a3323f694514a3035fbe/5-exploring-reliability-</u> <u>standard-metrics-in-net-zero-transition.pdf</u>

alternative metrics, their interaction and impact on capacity targets and the reliability framework. We will evaluate the case for changing the Reliability Standard, giving careful consideration to the potential for wider impacts on security of supply to arise during a transition to a new standard. If we determine any changes are required, we will consult before they are implemented. We are not considering any changes to the Reliability Standard in the short term.

Capacity Market Emissions Limits

The January 2023 CM consultation sought views on introducing lower emissions limits for new build and refurbishing Capacity Market Units (CMUs). We proposed that new and refurbishing CMUs with multi-year agreements awarded in relevant auctions following implementation, (which run beyond 2034) would, from 1 October 2034, have to meet an emissions intensity limit of 100gCO₂/kWh or a yearly emissions limit of 350kgCO₂/kW. The emissions limit would limit operations to approximately 750 hours per year for a typical gas peaking plant.⁵⁹ These limits would help ensure that the CM is aligned with the broader ambition for a fully decarbonised electricity system by 2035, subject to security of supply.

The respondents to the consultation were broadly supportive of greater alignment of the CM with net zero, with over half the responses being supportive of the proposed emission limits. Some called for more ambitious measures. Those which did not support the proposal raised concerns about the replacement of unabated gas capacity and the impact on security of supply. In the June 2023 government response to the CM consultation, we stated that government would seek to introduce the lower emissions limit for new build and refurbishing plant from 2024 at the earliest, subject to further analysis and development.

Whilst we remain committed to introducing the lower emission limits, additional consideration needs to be given to the timing of implementation. As such we will not implement the limits until the 2026 CM auctions at the earliest.

Questions:

- 16. Do you agree with the proposal that new lower emissions limits for new build and refurbishing Capacity Market Units (CMUs) on long-term contracts should be implemented from the 2026 auctions at the earliest?
- 17. If you are considering investment in flexible capacity, to what extent would emissions limits for new build and refurbishing capacity impact your investment decisions?

Delivering the flexibility needed for a secure and decarbonised power system

Increasing the deployment of long-duration flexibility

Providing the flexibility required to manage a predominantly renewables-based system in the 2030s and beyond will require a mix of solutions to effectively balance supply and demand over both short-duration and long-duration timeframes. Long-duration flexibility will be essential

⁵⁹ DESNZ, 2023, Capacity Market 2023: strengthening security of supply and alignment with net zero (Phase 1) <u>https://www.gov.uk/government/consultations/capacity-market-consultation-strengthening-security-of-supply-and-alignment-with-net-zero</u>

for ensuring stability and security of electricity supply during longer periods where renewable generation is not able to meet demand. As set out in the above section, we expect that the GB electricity system could require between 30 and 50GW of long-duration flexibility by 2035. The government's aim is for as much of this long-duration capacity as possible to be low carbon.

The roll-out of renewables has significantly reduced carbon emissions from the power sector, by reducing the role of fossil fuel generation across the electricity system: annual electricity generation from coal, oil, and gas fell by 55% between 2010 and 2022.⁶⁰ At present however, our primary long-duration flexible technology is unabated gas. Unabated gas generation currently plays a critical role in ensuring our electricity system remains stable and secure. It made up 38% of our total electricity generation mix in 2022.⁶¹ In times of peak demand and low renewable generation, unabated gas plays an even more critical role. As we expand the deployment of low carbon long-duration alternatives, the role for unabated gas will be reduced. However, all of government's modelled scenarios, as well as the Climate Change Committee (CCC),⁶² see a small but important peaking role for unabated gas out to at least 2035 to provide security of supply. The CCC's 2023 report⁶³ notes that a power system without unabated gas in 2035 would be likely to increase costs and delivery risks.

Over the coming years, a large proportion of our unabated gas capacity will be nearing the end of its life. Independent research published alongside this consultation suggests that under current market conditions, by 2035 almost half our current gas capacity could retire.⁶⁴ At the same time, peak electricity demand is set to increase as heat, transport and industry electrify. We must ensure that sufficient long-duration flexibility is in place to guarantee security of supply during the transition to a fully decarbonised electricity system. New investment in long-duration flexible capacity will be needed in the coming years to replace expiring plants and ensure security of electricity supply.

To this end, we are working to support the deployment of low carbon long-duration flexibility such as Power CCUS, H2P and LDES technologies, and mitigate potential barriers indicated by analysis, some of which are specific to individual technologies, and some of which are likely to exist for any First of a Kind technology.

Access to low carbon infrastructure, such as hydrogen and CO₂ transport and storage networks, is key to enabling deployment of low carbon long duration flexible capacity and is therefore critical to maintaining security of electricity supplies. It is also essential to provide a clear future decarbonisation pathway for our remaining unabated gas generation, helping reduce costs and risks to our security of supply as we transition away from gas generation. To overcome infrastructure barriers, the government's CCUS and hydrogen programmes are seeking to address the need for power projects to have access to the necessary transport and storage infrastructure for CO₂ and/or hydrogen. In addition, policy is being developed to bring forward the investment required to scale low carbon long-duration flexibility at pace. This extensive build-out of low carbon flexible capacity and supporting infrastructure to secure

⁶⁰ DESNZ, 2023, Digest of UK Energy Statistics (DUKES). Chapter 5, Table 5.6., available at:

https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes 61 DESNZ, 2023, Digest of UK Energy Statistics (DUKES). Available at:

https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2023

⁶² Climate Change Committee, 2023, Delivering a reliable decarbonised power system. Available at: <u>https://www.theccc.org.uk/publication/delivering-a-reliable-decarbonised-power-system/</u>

- ⁶³ Climate Change Committee, 2023, Delivering a reliable decarbonised power system. Available at: <u>https://www.theccc.org.uk/publication/delivering-a-reliable-decarbonised-power-system/</u>
- ⁶⁴ Baringa Partners, 2023, Assessing the deployment potential of flexible capacity in Great Britain an Interim Report. Available at: <u>https://assets.publishing.service.gov.uk/media/65e3a3a32f2b3bbc587cd767/8-assessing-deployment-potential-flexible-capacity-gb-interim-report.pdf</u>

electricity supplies through to 2035 and beyond will need sustained investment through public policy frameworks to leverage private finance.

Alongside industry and investors, the government has developed the Dispatchable Power Agreement (DPA) to incentivise CCUS to play a flexible mid merit role on the system, not displacing renewables and nuclear but running ahead of unabated gas. The government has passed the legislation needed to bring forward Power CCUS – and is in negotiations to deliver GB's first Power CCUS project in the mid-2020s. To build on this, government has stated its longer-term plans in the 2023 call for evidence response on the future policy framework for Power CCUS⁶⁵ and the recent CCUS Vision,⁶⁶ including an objective to bring forward multiple additional Power CCUS projects by 2030, subject to value for money, affordability, and CO2 storage availability, as part of establishing the UK's first four CCUS clusters.

On H2P, we published a consultation in December 2023 seeking views on the need and potential design options for market intervention to support H2P deployment.⁶⁷ The consultation sought views on the government's minded-to position that a market intervention for H2P could be required to mitigate our identified deployment barriers. We also sought views on our minded-to position that a H2P business model, based on elements of the DPA designed for Power CCUS but adapted to suit the needs of H2P, would be the most suitable design option for H2P market intervention. To provide routes to market for a range of potential H2P projects, we also outlined proposals to enable H2P to compete in the Capacity Market as soon as practical.

In addition, a consultation on the need for bespoke support to bring forward investment in LDES was also published in January 2024.⁶⁸ It outlined the government's position that a revenue cap and floor could be required and sought views on initial design questions. Further detail on the policy approach proposed for each technology is set out in Appendix 3.

Based on our internal analysis we expect that a limited amount of new build gas capacity will be required in the immediate term to ensure a secure and reliable system, to replace existing generation capacity as it expires. It is the only mature technology capable of providing sustained flexible capacity whilst low carbon long-duration alternatives, such as Power CCUS, H2P, and LDES scale up as we move into the 2030s.

A range of factors, including uncertainty regarding the operation and life of existing generation assets, will impact the scale of the new build gas requirement and the role it will play in ensuring security of supply in the near term. Recent Capacity Market auctions have bought 0.5-2GW of new unabated gas capacity in each of the last four years. Our analysis - underpinned by independent research commissioned from Baringa - suggests that around 15GW of our existing combined cycle gas turbine (CCGT) fleet could retire by 2035.

⁶⁵ DESNZ, 2023, Call for evidence on the future policy framework for the delivery of power with Carbon Capture, Usage and Storage: Government Response. Available at:

https://assets.publishing.service.gov.uk/media/64e4e1bc4002ee000d57b52a/power-ccus-call-for-evidence-government-response.pdf

⁶⁶ DESNZ, 2023, Carbon capture, usage and storage: a vision to establish a competitive market. Available at: <u>https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-a-vision-to-establish-a-competitive-market</u>

⁶⁷ DESNZ, 2023, Hydrogen to power: market intervention need and design. Available at:

https://www.gov.uk/government/consultations/hydrogen-to-power-market-intervention-need-and-design 68 DESNZ, 2024, Long duration electricity storage: proposals to enable investment. Available at:

https://www.gov.uk/government/consultations/long-duration-electricity-storage-proposals-to-enable-investment

Independent analysis from the National Grid Electricity System Operator suggests that 25-27GW⁶⁹ of unabated gas could be required in 2035 to keep the lights on, in a Net Zero compliant scenario, while the National Infrastructure Commission has analysis showing that 22-28GW⁷⁰ could be required. Based on retirement rates for our existing gas power stations, we believe delivering this level of unabated gas capacity would mean building some new gas projects. Our own evidence suggests the levels of gas capacity assumed by the National Infrastructure Commission and Electricity System Operator in 2035, under their core Net Zero compliant scenarios, could not be delivered without some newbuild gas capacity.

We are also working to support the conversion of existing gas generators to low carbon alternatives. There are a number of relevant policies which are already in place or in development, including:

- **Financial support for low carbon conversion:** In addition to bringing forward more new low carbon flexible generation, bespoke support schemes like the DPA for Power CCUS also make it easier for existing generators to convert to low carbon in the years ahead.
- **Capacity Market "managed exits":** In the January 2023 CM consultation we called for evidence on barriers to the decarbonisation of existing CMUs.⁷¹ This included options for enabling unabated generators to exit an existing multi-year CM agreement to access a new CM agreement or alternative support schemes to decarbonise, subject to ensuring continued security of supply and certain conditions being met. We will continue working on developing policy to ensure that unabated capacity on the system with long-term CM agreements has pathways to decarbonise.
- Enabling H2P and Power CCUS participation in the CM: In the H2P market intervention consultation, we sought views on enabling H2P and Power CCUS participation in the CM as soon as practical. Enabling participation in the CM would be subject to further consultation on finalising this policy proposal. Government would work with CM delivery partners and industry to understand and assess the role H2P and Power CCUS can provide in security of supply and the system. We will continue to consider the case for establishing a Generating Technology Class in the CM for Power CCUS.
- Establishing a 9-year Capex threshold: In the recent CM consultation, we have proposed the introduction of a midpoint 9-year Capex threshold for new and refurbishing projects. This longer multi-year agreement should provide increased revenue certainty for low carbon refurbishing projects which would have otherwise only been eligible for a 3-year agreement.
- **Decarbonisation Readiness:** We intend to publish our response to the March 2023 Decarbonisation Readiness consultation shortly and legislate for changes this spring, subject to parliamentary time. The proposed requirements would ensure new build and substantially refurbishing combustion electricity generators are built in such a way that

⁶⁹ Figures come from 2023 FES's consumer transformation and system transformation scenarios. ESO, 2023, Future Energy Scenarios. Available at: <u>https://www.nationalgrideso.com/future-energy/future-energy-scenarios-fes</u>

⁷⁰ Aurora, 2023, The role of system flexibility in achieving net zero. Available at: <u>https://nic.org.uk/app/uploads/Aurora-Role-of-system-flexibility-in-reaching-net-zero-A.pdf</u>

⁷¹ DESNZ, 2023, Capacity Market 2023: Strengthening security of supply and alignment with net zero (phase 1) Consultation Outcome. Available at: <u>https://www.gov.uk/government/consultations/capacity-market-consultation-strengthening-security-of-supply-and-alignment-with-net-zero</u>

they can easily decarbonise in the future by converting to 100% hydrogen-firing or retrofitting carbon capture within the plant's lifetime. These requirements would ensure that any new build unabated gas generation which comes forward to meet security of supply needs is in the best position possible to decarbonise in future.

 Carbon pricing: We also expect that carbon pricing through the Emissions Trading Scheme (ETS) and Carbon Price Support (CPS)⁷² will play a role in incentivising and increasing the competitiveness of alternatives to unabated gas. Government has set the ETS cap to be consistent with delivery of net zero, and recently published an updated auction calendar for 2024 to reflect this cap.⁷³

Questions:

- 18. Considering the policies listed above, which are already in place or in development, what do you foresee as the main remaining challenges in converting existing unabated gas plants to low carbon alternatives?
- 19. Do you think there is currently a viable investment landscape for unabated gas generation to later convert to low carbon alternatives? If not, please set out what further measures would be needed.

Supporting deployment and utilisation of distributed low carbon flexibility

Distributed, low carbon flexibility refers to low carbon assets connected to the distribution system that can provide flexibility, including batteries and DSR.⁷⁴ We expect increasing and significant quantities of these technologies to connect to the system, especially through the electrification of heating, transport and industry. Without incentivising these assets to act flexibly, we risk adding to the already challenging evening peak demand.

Schemes such as the ESO's Demand Flexibility Service (DFS) and the increased levels of flexibility procured by Distribution Network Operators (DNOs) show the role that these technologies are already able to play in our system. In the reporting cycle April 2022 to March 2023, DNOs awarded contracts for 1.87GW of flexibility services worth approximately £5.4 million, of which more than 70% were from low carbon sources.⁷⁵ Continuing to strengthen market signals and drive investment in these technologies will be critical to maximising the amount of renewable generation on the system, and reducing the amount of new generation and network assets that need to be built.

As set out in the above section, a range of internal and external models demonstrates that the system could need up to 55GW of low carbon short-duration flexibility by 2035 for a secure and cost-effective system. To drive the significant levels of investment needed, the government recognises the importance of contracts that provide a secure revenue stream and is therefore proposing to introduce multi-year agreements for low and mid-Capex and low carbon capacity

https://www.gov.uk/government/publications/uk-emissions-trading-scheme-markets/uk-emissions-trading-schememarkets

⁷² CPS - fixed at £18.

⁷³ DESNZ, 2024, UK Emissions Trading Scheme markets policy paper. Available at:

⁷⁴ Distributed low carbon flexibility includes commercial/industrial/public sector or households providing demand side response by increasing, decreasing or shifting their electricity such as water pumps, heat pumps, HVAC, heating systems, fridges and freezers, EV charging or, in future, electrolysers (producing hydrogen through electrolysis) which flex their demand in response to wholesale market prices; or electricity storage including commercial or domestic batteries. In future, sites could also have hydrogen backup generators.

⁷⁵ Energy Networks Association, 2023, Flexibility Figures. Available at: <u>https://www-energynetworks-org.webpkgcache.com/doc/-/s/www.energynetworks.org/assets/images/Publications/2023/230814-on23-flexibility-figures-2023-24.xlsx?1695567797</u>

in the CM.⁷⁶ Furthermore, the proposals being considered for an Optimised CM (as set out in the above section) would also provide an enduring investment support mechanism for low carbon flexible assets, that distributed assets would also be able to benefit from.

Our engagement to date has confirmed the position set out in the first REMA consultation, that sharper operational signals are required to strengthen the investment case for distributed flexibility. Operational signals are the price signals sent by markets to reflect system needs and incentivise flexible operation at the right times and locations, but there are a range of barriers that weaken and distort these signals. Sharpening them will incentivise investment by creating opportunities for market participants to earn revenue and therefore be rewarded for the system services they can provide. The key barriers to sharper operational signals are:

- inefficient market operations;
- barriers to market access;
- temporal signals that do not fully reflect system needs; and
- locational signals that do not fully reflect system needs.

There is a significant amount of work already underway to address these barriers, which is summarised in Appendix 3. This includes actions from the 2017 and 2021 Smart Systems and Flexibility Plan (published jointly with Ofgem), our work on 'Delivering a Smart and Secure Electricity System', the retail market reform programme and the Energy Digitalisation strategy. Some recent developments for flexibility markets include the ESO, soon to be NESO, committing to publish a Flexibility Strategy in the first half of 2024. This will set out the vision, key milestones and a transformation roadmap for enabling participation from all low carbon flexibility in markets. Additionally, Ofgem have published a decision on the future of local energy institutions and governance⁷⁷ in November 2023 – one of the intentions is to assign a market facilitation function to a single entity to deliver more joined-up flexibility markets. Finally, government recently announced the winners of the £2.6m Flex Markets Unlocked⁷⁸ innovation competition. This aims to support the design and development of technical solutions that can facilitate system-wide coordination, standardisation, and revenue stacking across multiple flexibility markets.

We will continue to work with Ofgem and industry to accelerate progress in order to deliver more open, transparent and co-ordinated flexibility markets. This includes exploring the role of suppliers and load controllers in bringing forward demand side flexibility, as part of our wider retail reform and Smart and Secure Electricity System (SSES) programmes. The SSES programme will be publishing a package of consultations in early 2024 addressing a licensing regime for DSR service providers, data interoperability of time of use tariffs, and requirements for energy smart appliances needed to protect consumers and the energy system. We published a response to our recent call for evidence on Innovation in the Energy Retail Market on 23 February 2024, setting out the next steps for our ongoing programme of energy retail market reform.

https://www.ofgem.gov.uk/publications/decision-future-local-energy-institutions-and-governance ⁷⁸ DESNZ, 2023, Flex Markets Unlocked innovation programme. Available at: https://www.gov.uk/government/publications/flex-markets-unlocked-innovation-programme

 ⁷⁶ DESNZ, 2023, Capacity Market 2023: Phase 2 proposals and 10 year review. Available at: <u>https://www.gov.uk/government/consultations/capacity-market-2023-phase-2-proposals-and-10-year-review</u>
 ⁷⁷ Ofgem, 2023, Decision on future local energy institutions and governance. Available at:

We have also identified some specific market issues which are exacerbating the four barriers listed above. In the coming months we will work with relevant groups to explore these barriers and consider improvements that could be made within existing market frameworks. These specific issues are skip rates and dispatch transparency in the Balancing Mechanism, baselining methods for DSR, the standardisation and simplification of markets to improve revenue stacking, lowering participation thresholds and introducing closer to real time procurement. In Appendix 3, we have provided a more detailed description of each of these and, if applicable, a summary of the work already underway which might help address them.

Alongside the work that is already underway, there are several key REMA proposals outlined in Challenge 4. This includes options to sharpen locational and temporal signals and maintain operability that, if implemented, would have an impact on these market signals and potentially help to address the barriers listed above. In the next stage of the REMA programme, we will continue to assess the impact of our emerging policy options on distributed low carbon flexibility using the 'whole system flexibility' assessment criteria, together with progress towards implementing the work already underway. As we finalise the REMA package of proposals we will review the impact of this package, together with our ongoing work on price signals for distributed low carbon flexibility, to determine whether further intervention is required.

Question:

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

Transitioning away from bespoke support

Bespoke support mechanisms may be essential for developing and building confidence in novel low carbon flexible technologies. But as technology specific barriers are overcome and enabling infrastructure is rolled out, there are strong arguments for transitioning back to technology neutral, price-competitive allocations at the earliest opportunity. This will harness the power of markets to identify the most cost-effective technologies and deliver best value for consumers.

Earlier in this section we set out our proposal to introduce minima in the CM (i.e. Optimised CM). Once a certain level of technology readiness and infrastructure availability has been met, this proposal provides a route to transition low carbon long-duration flexible technologies away from any administratively awarded bespoke mechanisms, whilst offering continued revenue support. In the long-term, the Optimised CM should be the primary scheme for supporting the deployment of a competitive mix of low carbon flexibility.

We will keep the progress of any low carbon flexible technologies in receipt of bespoke support under review until we have confidence that they are able to compete in an Optimised CM, noting that this may occur at different times for different technologies or for different types of projects. When it is appropriate to do so, we will consider tightening eligibility for bespoke support in order to move technologies or types of projects into the Optimised CM.

We acknowledge there may be a need to continue to offer bespoke support into the 2030s for certain low carbon flexible technologies, for example to mitigate ongoing cross-chain or other

risks. As set out in the recently published CCUS Vision⁷⁹ and H2P consultation,⁸⁰ the government may look to introduce price-based competition into any bespoke mechanisms as a stepping stone towards technology neutral allocations.

Question:

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

Discounted options

We have reviewed a number of alternative and add-on options from our first consultation but have found that the proposed package of reform above would deliver better results. Therefore, the following options will not be taken forward for further consideration: cross-technology revenue cap and floor, Centralised Reliability Options, Strategic Reserve, and a Targeted Tender. We have summarised our rationale for discounting each option below. Further detail can be found in the Options Assessment published alongside this consultation.

Discounting a cross-technology revenue cap and floor

We have decided to discount using a revenue cap and floor (RCF) as a mechanism to provide investment support for all low carbon long-duration flexible technologies (Power CCUS, H2P and LDES). This is primarily because any revenue-based model such as a RCF comes with a risk of gaming, as cap and floor payments are calculated based on the revenues that a generator earns. There are several ways in which the revenues reported under the RCF could be manipulated to receive a greater payment. This risk is greater for dispatchable generators than interconnectors (whose revenues are regulated and transparent) because they have multiple routes to market. 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.

In addition to this gaming risk, we also have concerns that a RCF could limit dispatch incentives for dispatchable assets if asset operators judge that they will fall outside the cap or floor. Under the REMA proposal, the floor would be set through a competitive pay as clear auction. There is risk the auction clears at a floor level higher than some projects need, which would be poor value for money for government and would exacerbate the dispatch issue. Finally, as raised by respondents to the initial REMA consultation, there is a risk that a proposal supporting only high Capex assets (such as Power CCUS, H2P and LDES) could distort the market for low carbon flexibility by improving the investment case for these technologies over more cost-effective alternatives.

⁷⁹ DESNZ, 2023, Carbon capture, usage and storage: a vision to establish a competitive market. Available at: <u>https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-a-vision-to-establish-a-competitive-market</u>

⁸⁰ DESNZ, 2023, Hydrogen to power: market intervention need and design. Available at: <u>https://www.gov.uk/government/consultations/hydrogen-to-power-market-intervention-need-and-design</u>

Discounting Centralised Reliability Options

We have decided to discount Centralised Reliability Options (CROs) as an alternative primary capacity mechanism to the CM. 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-based system. We found that the current evidence from international examples does not alleviate our concerns in terms of the mechanism enabling sufficient investment in new capacity to ensure security of supply. 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.

Discounting Strategic Reserve

We have decided to discount a Strategic Reserve (SR) as a supplementary add-on mechanism to the CM (having discounted it as an alternative primary mechanism following the first consultation). Although we can see potential benefits of a SR in some limited future scenarios, we do not consider that taking capacity out of the wholesale market and paying for it to be operational only at times of system stress is either cost-effective or necessary at this stage. Further, we have confidence that our plans for an optimised CM will deliver the capacity we need while also supporting development of low carbon flexible generation. Introducing a SR alongside the CM could also have drawbacks such as added complexity and a reduction in liquidity.

Discounting Targeted Tender

We have decided to discount a Targeted Tender (TT) as a supplementary add-on mechanism to the CM (having discounted it as an alternative primary mechanism following the first consultation). While a TT could potentially be used in a range of circumstances, for example to procure capacity in specific regions or with specific characteristics, we consider that existing arrangements are sufficient to deal with any circumstances that a TT might be deployed in. We also had significant concerns with the option, particularly related to its cost-effectiveness, as well as effects on market power and competition.

Conclusions and next steps

In this section we have set out that:

- We estimate the GB electricity system could require up to 55GW of short-duration flexibility and between 30 and 50GW of long-duration flexibility by 2035 to ensure security of supply. The government's aim is for as much of this long-duration capacity as possible to be low carbon.
- New investment in long-duration flexible capacity will be needed in the coming years to replace expiring plants and ensure security of electricity supply. Based on our internal analysis we expect that a limited amount of new gas capacity will be required in the immediate term to ensure a secure and reliable system. It is the only mature technology capable of providing sustained flexible capacity whilst low carbon long duration alternatives, such as Power CCUS, H2P and LDES scale up.

- We will progress the development of bespoke policy to support deployment of low carbon long-duration flexibility in the short term, including through the consultations on H2P and LDES published in December 2023 and January 2024 respectively.
- To ensure clear decarbonisation pathways for our remaining unabated gas generation, greater hydrogen and CO2 capacity would need to be available in future. This extensive build-out of low carbon flexible capacity and supporting infrastructure to secure electricity supply through to 2035 and beyond will need sustained investment through public policy frameworks to leverage private finance.
- We will retain the CM as our capacity adequacy mechanism but optimise the auction to further support low carbon flexibility by introducing minima.
- We will continue to assess how minima interacts with the broader CM set up, prospective bespoke support mechanisms and REMA package to ensure optimal use.
- We will identify where additional optimisation may be required to ensure the CM effectively delivers REMA's objectives.
- We will review the GB Reliability Standard to ensure the metric effectively addresses future risks to security of supply. We are not considering any changes to the standard in the short term. If any specific proposals on the reliability standard are identified, then these will be considered and consulted on in conjunction with the Optimised CM. As part of this, we will give careful consideration to any broader security of supply impacts that could arise during a transition to a new standard.
- We will continue to work with Ofgem, the ESO and industry to accelerate progress and reforms within the current market framework to bring forward distributed low carbon flexibility.
- We will review the impact of the finalised REMA package together with our ongoing work on price signals for distributed low carbon flexibility, to determine whether further intervention is required.

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

Challenge summary

In this section, we explore the following questions:

- How do we ensure that efficient price signals are sent in the wholesale market so that whole-system costs are minimised?
- How do we improve mechanisms and markets for balancing the system?
- How do we ensure sufficient liquidity is maintained under future market arrangements?

Summary of proposals in this section:

Chanenge 4. Operating and optimising a renewables-based system, cost-enectively					
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				
Key Current arrangements continue REMA options – under consideration * Not fully discounted, but not being considered as a stand-alone option					

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

The emerging electricity system is transitioning from one designed for firm, flexible generation to one which is renewables-based. This transition is resulting in a range of challenges, as well as opportunities, that our wholesale market arrangements will need to meet in order to deliver a secure and cost-effective system.

The future system will need to send efficient locational and temporal signals so that supply and demand are better matched and balancing costs minimised. It will also need to ensure that the Balancing Mechanism and ancillary services markets operate effectively within a decarbonised system, that there is effective coordination between the distribution and transmission networks, and that the market is sufficiently liquid. The first REMA consultation set out a range of options to address these challenges, including introducing locational pricing, reorientating the market towards the distribution network ('local markets'), incremental reforms to the parameters of the status quo (such as gate closure or settlement periods), and a wide range of options for ensuring operability.

Since the first consultation, we have assessed the options to reform the wholesale market, including new options raised by stakeholders in response to the consultation. We have decided to continue to consider locational pricing in the form of zonal pricing, as well as a range of alternative options to locational pricing which would operate under a single national price. Introducing more efficient locational signals in the market could deliver significant value for consumers. We have, however, decided to discount nodal pricing from further consideration in the REMA programme on the grounds of investor confidence and deliverability of our 2035 decarbonisation targets. In the next stage of REMA, we will seek to work closely with industry, ESO/NESO, and Ofgem to develop both national and zonal models of wholesale market reform to enable a comparison between the two with the aims of designing models which can most appropriately allocate risk to market participants while delivering savings for consumers.

We will also continue to consider where reforms to status quo elements such as settlement periods, the Balancing Mechanism, and operability services can deliver benefits for the system and consumers. We will no longer consider the 'local markets' model; instead, we will continue to consider what further actions are needed in order to deliver open, dynamic and coordinated markets for distributed low carbon flexibility. We will also continue to monitor how REMA options may impact liquidity in electricity markets.

Alongside REMA reforms, the government is also implementing or considering a range of policy actions to help drive down balancing costs and lower consumer bills outside of markets. This includes actions to accelerate the pace of network build and to take a more strategic and co-ordinated approach to spatial planning for energy infrastructure.

Transitioning to a net zero wholesale market

Our electricity market arrangements were established in an era of large, centralised, fossil fuelbased generation, located across the country. Since then, huge strides have been made in the deployment of low carbon generation, on the journey to a fully decarbonised electricity system by 2035, subject to security of supply. As a result, the system is changing to one which is more heavily based on renewables alongside a range of smaller, distributed flexible generation and storage assets. Demand profiles are also changing, as electrification of heating and transport increases and more distributed flexibility comes online.

This technological transition has, and will continue to, significantly reduce the carbon intensity of the power sector. But it is also introducing new challenges for keeping the system operating dependably and cost effectively. This matters for a secure and reliable supply and to keep consumer bills as low as possible because:

• Generation output is becoming harder to predict, as it is more dependent on the weather.

- Electricity demand will also become harder to predict as in future it will depend on demand for heating which will be weather dependent, and electric vehicle charging patterns.
- Generation is located further from demand, putting additional strain on networks, and creating challenges for system operation.
- Generation is no longer providing the same suite of operability services needed to run the electricity system securely e.g. inertia.
- New sources of flexibility are coming into the system and are increasingly located at distribution level where they are less visible to the System Operator, making it harder to co-ordinate and use them efficiently.

As a result, balancing and system operation costs which ultimately fall on consumers are rising, and we expect this to continue in future. A wide range of actions are already being taken to address these issues. REMA is reviewing whether more fundamental changes to electricity market arrangements are required in addition to this.

Summary of REMA options

In the first REMA consultation we sought views on initial options to address these challenges. Since then, we have focused on narrowing down and refining options for reform to focus on what is most likely to have a positive impact. There are five groups of options that we are considering as part of Challenge 4:

- Improving locational signals
- Improving temporal signals
- Improving balancing and ancillary services
- Improving local and national market co-ordination
- Improving market liquidity

Improving locational signals

Case for change

The transition to a low carbon electricity system means generation is increasingly locating further from demand, for reasons including access to necessary resources, for example abundant wind or enabling infrastructure for carbon capture and hydrogen production.

This emerging system, where the location of supply and demand is increasingly at odds, is putting additional strain on network infrastructure in the form of greater periods of network constraints - times when parts of the network are at capacity and physically incapable of transporting additional energy from one point to another (e.g. from North Scotland to Southeast England).

GB's physical network infrastructure and the ESO's operational tools are both increasingly struggling to manage this system. Under current arrangements, the ESO must instruct generators behind network constraints to turn their output down (they are curtailed), receiving compensation for doing so, and generators in front of network constraints to turn up so that overall demand can still be met. This activity happens predominantly through the Balancing Mechanism one hour before the system is dispatched, and the costs of these actions are ultimately passed onto consumers.

Constraint costs have risen significantly in recent years, from around £0.7bn in 2018/19 to £1.8bn in 2022/2023, with balancing actions at times exceeding 50% of national demand.⁸¹ Based on the evidence of historic delays to network build, ESO analysis, commissioned by DESNZ, indicates that a 3-year delay in network build could increase the annual cost of curtailment up to around £8bn⁸² in the late 2020s – or the equivalent of around £80 on the average annual household electricity bill.

Resolving this challenge is therefore one of the most significant issues which needs to be addressed in our future electricity system.

Incentivising efficient locational decisions and minimising the costs of constraints are primarily managed through policy for planning, networks, and markets. However, the incentives across these policies can at times be fragmented or insufficient to address the scale of the challenge.

- Planning permissions help drive where investments are made but can vary across Devolved Administrations.⁸³
- The network policy of 'connect and manage', which delivers earlier grid connections, means generation is connected before the full extent of network infrastructure is available for that asset, and 'firm access' rules compensate generators during those time periods where the network is unable to deliver their energy to demand.
- The effectiveness of locational price signals sent through network charging to influence where assets are built is arguably reduced by their unpredictably and volatility. We also have no locational market signals to influence how assets should operate – for instance enabling assets to dispatch in ways which most support the system.

Taken together, this means that signals to influence locational decisions – for both investment and system operation – can be blunted and inefficient. Investors and plant operators do not need to adequately consider location in their decision making, and consumers pay the cost of resolving inefficient outcomes.

A range of policy actions are already under consideration or under way outside the REMA programme to help drive down constraint costs and lower consumer bills. Work is underway to accelerate the pace of network build, including via the government's response to the recommendations of the Winser review, and to increase investment in both the transmission and distribution network. For example, Ofgem's Accelerated Strategic Transmission Investment (ASTI) scheme will accelerate the delivery of nearly £20bn of investment in

⁸¹ National Grid ESO net zero Market Reform Phase 3 Conclusion March 2022.

⁸² ESO Analysis for DESNZ, Undiscounted, 2022/23 prices.

⁸³ For instance, onshore wind in England is subject to additional planning conditions. In September 2023 the Government updated the National Planning Policy Framework at footnotes 57 and 58 to stipulate that onshore wind must be built in an area identified as suitable in a local planning document, and that the community must support the proposal: <u>https://questions-statements.parliament.uk/written-statements/detail/2023-09-05/hcws1005</u>

strategic transmission projects and Ofgem's RIIO-ED2 price control provides core funding of £3.1bn for investment in distribution network upgrades.⁸⁴

The Prime Minister also announced in September 2023 that we will take a more strategic and co-ordinated approach to spatial planning for energy infrastructure to ensure a better match between supply and demand, building on recent improvements to the way in which the network is planned such as the Holistic Network Design and Ofgem's work to deliver a Centralised Strategic Network Plan. Government and Ofgem have also published a Connections Action Plan⁸⁵ to reduce connection timescales to ensure generators can connect to the electricity network both where and when they are needed to meet demand and support the transition to net zero.

However, these actions will only take us so far. A future renewables-based electricity system is still likely to experience greater periods of network congestion than the system before it, even once major network reinforcements are brought online. And an efficient system will have to balance both network reinforcement and generation curtailment. It would not be feasible or cost-effective to expand network capacity to prevent all curtailment, as some of the network capacity would have very low utilisation. In addition, non-market interventions through regulatory regimes such as planning can have significant influence on where assets are built, but typically have little influence on the economics of day-to-day operation, for example on the management of system constraints in real time. Our analysis suggests how assets operate day-to-day is where the majority of system and consumer benefits may lie.

REMA is therefore considering options for sending more efficient locational signals through electricity markets. Introducing more efficient locational market signals could deliver additional benefits to those introduced through future 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.

They can also help to optimise the use of low carbon flexibility, such as batteries, and crossborder interconnectors. The direction of energy flows on interconnectors, for example, is determined by the price differentials between connected markets, with energy generally flowing towards the higher priced market. A lack of efficient locational signals in GB means that interconnectors can at times flow counter to GB system needs. Energy may be being exported from locations in GB where more generation is needed (i.e. in the South of England) and being imported into locations where energy cannot be transported to the rest of GB due to network constraints (i.e. Scotland). More effective locational operational signals could therefore mean interconnector flows are better optimised and reflective of the needs of the GB system. This could improve system efficiency and lower overall system costs.

Market signals therefore have a crucial role to play in addressing this issue, as part of a comprehensive approach alongside non-market factors.

⁸⁴ This is over the period 2023-28, with the opportunity for this to increase, depending on the rate of decarbonisation.

⁸⁵ DESNZ & Ofgem, 2023, Electricity networks: connections action plan. Available at: <u>https://www.gov.uk/government/publications/electricity-networks-connections-action-plan</u>

Options for sending more efficient locational signals

There are two types of locational signals which can be sent through markets:

- Locational investment signals incentivising where new assets should be built; and
- Locational operational signals incentivising assets to produce or consume energy in a way that is beneficial for the system.

We have considered two sets of market-based options for sending more efficient locational signals:

- Locational pricing options: Nodal and zonal pricing. These options send both locational investment and locational operational signals through the wholesale market.
- Alternatives to locational pricing options: transmission network charging reform, transmission network access reform, measures for constraint management, optimising the use of cross-border interconnectors, locational CfD and locational CM. These options primarily send a locational investment signal, outside of the wholesale market.

The two sets of options come with different benefits and risks. Locational pricing, by sending both investment and operational signals, may be able to deliver a wider set of benefits and address a fuller extent of challenges outlined above, but implementation of these options is likely to be more challenging. In contrast, the alternative set of options build on existing arrangements and, in most cases, will incur less implementation risk than locational pricing. However, the potential benefits of these alternative options is likely to be more limited because they have limited potential to send operational signals – which make up a large proportion of the benefits of locational pricing.

The options sets are generally mutually exclusive, although there is some limited potential to use the alternatives to locational pricing to deliver benefits before other decisions are taken. Most of the alternative options though are expected to have similar implementation timeframes to locational pricing.

Options set 1 – Locational pricing options – assessment of options and rationale for decisions

The aim of locational pricing is to incentivise generation and demand, where they are able, to (i) locate in parts of the network where they would offer most value to the system and (ii) operate more efficiently to lower system costs. Locational pricing would embed the locational value of energy into the wholesale price of electricity so it reflects the balance of supply and demand, as well as available network capacity, in each location. This would mean different geographic locations would have different wholesale prices. Under locational pricing, one would expect areas with significant generation output relative to demand to have lower wholesale prices and vice versa.

In the first consultation, we presented two options for introducing locational pricing: zonal pricing and nodal pricing. These markets are common internationally, with nodal markets prevalent in the United States, including Pennsylvania – New Jersey – Maryland (PJM), California (CAISO) and Texas (ERCOT), and zonal markets used in some European electricity markets, including Italy, Norway, Denmark, and Sweden. The difference between the two is price granularity and dispatch. Nodal pricing sends a more granular locational signal, delivering different prices at hundreds of transmission nodes, but would require centralised dispatch from

the ESO (which is optional under some forms of zonal pricing models). Zonal pricing, in contrast, would split GB's wholesale market into a far smaller number of regional zones, for example up to maximum of a dozen.

The evidence we have collected suggests **there is a clear case for continuing to assess locational pricing**, specifically in the form of zonal pricing, due to the potential system operation and consumer savings it could offer.

DESNZ commissioned modelling shows that locational pricing under the form of zonal pricing could reduce the cost of running the electricity system in the region of c.£5-15bn over 2030-2050, and that consumer benefits could be in the region of c.£25-60bn over the same period. Assuming these savings are fully passed through, this would be an average consumer benefit of £20-45pa per household over 2030-2050. It is important to note that 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 expenditure. These results do, though, add to the body of evidence that indicates there is merit in the further examination and more comprehensive analysis of locational pricing.

We have therefore decided to continue to consider locational pricing as an option to deliver more efficient locational signals. However, we believe the risks to investor confidence and deliverability of our 2035 decarbonisation targets are too great under nodal pricing. We have therefore decided to **discount nodal pricing**; this is explored further below.

Benefits of locational pricing

We believe there are several major benefits of locational pricing which no other options are likely to provide:

A more efficient system: Locational pricing sends locational operational signals - real-time price signals which ensure that supply and demand are better matched during dispatch and consumption. Locational pricing automatically 'translates' system constraints into the wholesale price signal, incentivising market participants to actively respond to changes in local levels of supply, demand, and network capacity. By sending these signals on how to operate, generators would only dispatch when the market needs them to and there is sufficient network to carry their capacity (limiting costs to turn them on/off). Demand would be incentivised to consume electricity when it is cheap and abundant – lowering prices for consumers.

Market signals are also adaptive, future-proofing against delay or under-delivery of network build, minimising system costs until build catches up with renewables penetration. This can help to deliver a smaller and more efficient electricity system, this includes reducing the scale of investment needed for both generation and network infrastructure.

Lowering consumer bills: Our analysis shows that, even when consumers are shielded from locational price signals, they see a net benefit under locational pricing.

Under national pricing arrangements, the wholesale electricity price is set by the national marginal plant (the most expensive plant to meet demand, which currently is usually a gasfired generator). As described in Challenge 1, this leads to 'inframarginal rent' for other generators which can raise consumer costs, though we expect this effect to reduce with the increasing roll-out of renewables on price-support mechanisms (such as a CfD).

Under zonal pricing, prices are instead set by the marginal plant within zones, which can reduce the 'inframarginal rent'. This reduced rent is transferred from generators back to consumers, reducing consumer bills. Locational pricing also reduces the volume traded in the

Balancing Mechanism and moves it into the wholesale market, which is more competitive and open, further reducing costs. This helps improve operation of the system as trading can resolve issues efficiently and more can be done ahead of time.

Potential to maximise whole-system flexibility and drive economic growth: As with better temporal signals, more granular locational signals could help maximise flexibility in the system. Through operational signals, locational pricing would make better use of all types of low carbon flexibility. As shown in our modelling, interconnectors and storage would be used more efficiently under locational pricing to help manage rather than (at times) exacerbate network constraints.

Locational pricing could also help unlock flexibility on the demand-side. Investment in demand side technologies could be made more attractive by passing through the benefits of potentially significantly cheaper electricity in over-supplied parts of the country. In the future, this could incentivise investment in different types of storage and hydrogen electrolysers. It may also drive new industrial investment and economic growth in areas with high levels of renewable generation. End users, particularly those that are energy intensive or can shift their electricity demand to match renewable output, may look to invest in new or expanded facilities in these regions, creating new jobs and opportunities for the local economy. It could also potentially lead to higher adoption rates of electric heat pumps and vehicles in areas with lower wholesale prices.

Greater demand-side-response could also be encouraged by incentivising end users to better match their electricity usage with the level of generation in their area in real-time, leading to better utilisation of renewable generation, reduced carbon emissions, and lower system operation costs. This could help incentivise demand-side response from a range of end users from homeowners optimising heat pump operations and EV charging, to large industrial facilities adjusting their production profiles.

However, the ability of different electricity users to respond to these signals will vary significantly and the distributional impacts will need to be considered carefully, including for energy intensive industries. In the next phase of REMA, we will consider how different options for exposing end users to locational price signals balance the need to optimise the electricity system while protecting those who may be unable to respond. Any potential move to locational pricing would be introduced carefully to give electricity end users time to adjust and enable adequate protections to be put in place where appropriate. Interactions with existing government schemes that protect some electricity consumers would also need to be carefully managed.

Risks of locational pricing

Potential increases in the cost of capital: Some assets would be less able to respond to locational signals as access to resource or infrastructure would take precedence. This could increase costs or decrease revenues for some existing assets (e.g. if they are in generally lower priced zones) or introduce new risks for new investments (e.g. if their revenues are less predictable), some of which could in turn be passed back to consumers in the form of increased financing costs.

The introduction of locational pricing, therefore, could increase the cost of capital for some assets due to these new risks. In some cases, these risks (and cost of capital increases) will be an intended consequence of the policy. This is because risks might e.g. incentivise developers to locate in more beneficial parts of the network, or incentivise more efficient operational behaviour, which could help to reduce the cost of running the electricity system.

However, if increases in cost of capital are too high, this could offset the savings made under locational pricing.

Locational pricing would increase the following risks for investors (which will likely affect the cost of capital):

- **Price risk** the risk that generators make less revenue under locational pricing than they would do under national pricing (e.g. if their zone has consistently lower wholesale revenues), or that revenues are less predictable (due to changes on local supply and demand).
- **Volume risk** the risk that generators are not dispatched as often (due to changes to their firm access rights) and therefore make lower and less predictable revenues.

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). There is significant dependency on precise policy design, and it is therefore not possible at this stage to robustly quantify the final impact on cost of capital. However, our view is that an increase as high as 3% is very unlikely under the market designs being taken forward by REMA, as these higher estimates are often underpinned by unfavourable assumptions, and we would not progress design choices that lead to such adverse impacts on cost of capital. Our intention is to engage extensively with market participants in the next phase of the programme to design a viable zonal model which strikes the balance between delivering effective operational signals and maintaining investor confidence.

Policy design could help mitigate against some risks, for example through design of the CfD or introducing effective hedging mechanisms. A range of hedging products exist internationally, including Financial Transmission Rights (FTRs) and Electricity Price Area Differentials (EPADs). If markets for these products were liquid and well-functioning, they could act as one route for generators to manage additional locational risk, alongside e.g. co-locating with storage or other flexible assets, or through diversifying their portfolios more broadly.

Implementation challenges: Introducing any form of locational pricing would be complex and take significant time. The level of difficulty would increase if central dispatch were also implemented in parallel. Alternative options would not necessarily be quick or simple to deliver, but do build upon more familiar existing arrangements. Locational pricing would have wide ranging impacts across several aspects of market design, and would require for example, reforms to trading arrangements, network access rights and the design of the BM (including to minimise gaming opportunities). It would also have impacts on existing or Legacy Arrangements across the market – see the Options Compatibility and Legacy Arrangements section for more information on the treatment of Legacy Arrangements.

Liquidity: There is international evidence to argue that both nodal and zonal models can have both a positive and negative influence on liquidity in the long-term. Due to varying characteristics in global markets as a comparator, it is challenging to infer what the impacts on liquidity within GB could be. However, given concerns about already low liquidity in GB electricity markets, we will need to consider any impacts carefully (see 'Liquidity in the Wholesale Market' below).

Adaptability: Zonal markets would likely require some intervention over time to continue to ensure that zonal boundaries accurately reflect system constraints. This need to review and redefine zones over time would create risks and uncertainties for market participants.

Risk allocation

These risks and issues need to be weighed against any potential benefits case, as set out in the accompanying Options Assessment. In particular, any potential increases in the cost of capital will need to be balanced against the possible benefits of more efficient system operation.

Locational pricing would affect how risk is allocated within market design, as it would transfer some of the responsibility for managing the risk of local supply and demand mismatches from consumers to generators by exposing them to greater locational price and volume risk. As noted in the Introduction, within risk allocation there is a central trade-off between delivering efficient system operation and keeping investment costs low. This means ensuring that any changes to the balance of risk are appropriately and efficiently allocated.

Locational pricing would represent a significant shift relative to current risk allocation, and it has the potential to deliver significant efficiency benefits because of this by incentivising siting and dispatch decisions that better reflect the balance of supply and demand geographically. However, certain design decisions could result in a suboptimal allocation of risk i.e. where locational pricing creates such significant revenue risk that it either hinders what would otherwise be viable investment decisions or leads to system-wide increases in financing costs which erode any efficiency gains.

There is also a balance between investment and operational risks and incentives. Investors may be less able to respond to long-run investment risks beyond their immediate control, such as delays to network build or significant changes to the generation or demand profile in their local area, but may be able to, through market incentives, help reduce system costs within operational timeframes in these cases.

Locational risk already exists within our current market arrangements, and different market participants will be able to effectively respond to new risks in different ways. In the next phase of assessment, we will carefully consider how different zonal pricing models, as well as alternative options to locational pricing, impact the level of risk faced by market participants and investors, and how this interacts with market design choices in other areas.

Discounting nodal pricing

Although some external studies have found nodal pricing could potentially deliver greater system benefits than zonal pricing, we believe the potential impact on investor confidence resulting from greater revenue uncertainty coupled with greater delivery risk has a significant chance of eroding any additional benefits. The increase in investor and deliverability risk is material, given that the GB future system will need to continue to deploy significant amounts of new generation at scale. Our assessment is also that the theoretical benefits of nodal pricing may be overstated through some modelling exercises.

Deliverability: Based on international precedent, we estimate zonal pricing could take at least 5 years to implement, and that nodal pricing (which would require central dispatch) up to a decade. Zonal pricing could be implemented with current self-dispatch arrangements as a less disruptive option which could still deliver significant benefits. Zonal models that retain self-dispatch could also be a stepping stone before a move to more complex models involving central dispatch if later required (depending on further assessment of the benefits of central

dispatch). There are also a wide range of precedents for aspects of zonal pricing in our current (or recent) market arrangements which should ease implementation (including alignment with cross-border trading arrangements) and help minimise market uncertainty during any potential transition.

Investor confidence: The overall benefits of locational pricing will depend on potential impacts on cost of capital driven by the risks that generators will face. These will depend upon policy design, which could help mitigate risks (for example through shielding renewables). However, both volume and price risk⁸⁶ would be larger under nodal than zonal pricing due to the complete loss of firm access and the greater price granularity. Available mitigations through policy design would be less likely to eliminate this difference altogether. Nodal pricing, therefore, has the potential to create greater uncertainty which could lead to higher increases to costs of capital which could offset system savings and disrupt our transition to 2035. Zonal pricing presents less risks to investors through less volatile prices and by retaining a greater level of wholesale dispatch certainty.

So, while we believe there is merit to continuing to consider if zonal pricing could help deliver a net zero electricity system at least cost, we are not confident that nodal pricing could deliver additional benefits commensurate with the additional risks. Further detail on our assessment is included in the accompanying Options Assessment.

For these reasons **we will not consider nodal pricing further under the REMA programme**. Instead, we will continue to consider models of zonal pricing which can most appropriately allocate risk to market participants while delivering savings for consumers.

Design parameters for a GB zonal pricing model

In the next phase of REMA's work, our focus will be to design a more detailed zonal pricing model which can be assessed alongside the set of alternative options to locational pricing (explored further below).

There would be a variety of ways to implement zonal pricing in GB. Design could vary from a light touch model which shields participants from certain risks and maintains current decentralised arrangements, to a more transformative model which might prioritise flexibility through sharper price signals and be more centralised in its operation. Key design choices for a zonal pricing model are outlined in Appendix 4.

Although most design choices for a zonal pricing model are yet to be made, we have established some key design parameters to give some assurance to stakeholders during the next phase of REMA.

Treatment of existing generation and flexibility assets: We recognise locational pricing would have implications for existing generation and flexibility assets and associated arrangements, including future investments established prior to a decision on locational pricing. The Options Compatibility and Legacy Arrangements section sets out proposals for their treatment in general. For generators with a CfD (including future allocation rounds prior to a decision on zonal pricing), a move to a zonal market would be likely to lead to a change of the reference price to be based on the market into which generators are selling their power i.e. the local, zonal market. This would ensure CfD generators are 'made whole' to their strike price, and insulates them from locational price risk for the length of their contract.

⁸⁶ Total price risk will also depend on exposure to prices in the Balancing Mechanism.

Consumer exposure: We will need to carefully consider the impacts which locational pricing could have on regional differences in consumer bills. Consumers already face regional differences in retail pricing due primarily to network charges. For example, in the January-March 2024 Default Tariff Cap, the electricity component of the typical household bill for those paying by direct debit varies by region. The difference between a typical annual household electricity bill in the East Midlands (which has the lowest costs) and a typical annual household electricity bill in North Wales & Mersey (which has the highest costs) is £84. Our initial analysis suggests that zonal price differentials could be of similar magnitude. This is discussed further in the accompanying Options Assessment. These differences could help smooth out existing regional network charging differences for most regions, although this may not be the case in all regions. Decisions on network charging are a matter for Ofgem, and we will work closely with them as part of the next phase of the REMA programme.

Whether consumers should be exposed to differential prices due to locational pricing is a design choice which will need to be considered further, taking account of the potential consumer benefits from enabling greater demand-side flexibility alongside further analysis on potential distributional impacts and the future trajectory of network charging. Our analysis shows that even when consumers are shielded from locational price signals, consumers see a net benefit from the introduction of locational prices are passed through, prices could further decrease for many customers. As set out in the accompanying Options Assessment, locational pricing has the potential to lead to savings for the typical household in all regions. This could be to a greater extent for consumers in constrained areas of higher supply & lower demand (e.g. North England and Scotland) and to a lesser extent for consumers in areas of lower supply & higher demand (e.g. London).

International implementations vary in the extent to which locational signals are passed through to different types of consumers. Locational pricing could be passed through to encourage greater demand-side flexibility. Alternately, there are models for how locational pricing could be introduced for generators but fully or partially blocked from flowing through into wholesale or retail prices for different types of consumers (including domestic and non-domestic/industrial consumers). It could be possible to do this while allowing some consumers who might benefit from more granular price signals to opt-into locational pricing. Some key design choices are noted in Appendix 4.

Cross-border energy trading: In our next phase of work, we will work closely with the EU and international trading partners to minimise any potential implementation risks for our cross-border trading arrangements. We will continue to take account of our international agreements and obligations for energy trading and cooperation, including the establishment of more efficient trading arrangements through Multi-Region Loose Volume Coupling (MRLVC).

Further key design choices such as determining the number of zones, the approach to reviewing zonal boundaries, dispatch arrangements, support scheme design, market power and gaming mitigations, access rights and hedging products, and the approach to interzonal capacity allocation are explored further in Appendix 4.

Question:

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

Options set 2 – Alternatives to locational pricing – assessment of options and rationale for decisions

Alongside work on locational pricing options, we have also assessed and developed alternative options for sending locational signals, outside of the wholesale market. Some of these alternative options were identified in the first REMA consultation and others have been identified and developed following further engagement with stakeholders.

Currently, the alternative options we are considering within REMA are:

- Using Ofgem's pre-existing network charging reform programme (option A).
- Reviewing Ofgem's transmission network access arrangements (option B).
- Expanding measures for constraint management (option C).
- Optimising the use of cross-border interconnectors (option D).

These options generally build upon existing arrangements and, in most cases, would carry less new risk for investors compared with locational pricing. However, some options could still entail significant reforms – for example, any change to access rights arrangements.

Like locational pricing, these options can be used to send a locational investment signal, meaning they could influence decisions on where to site new generation and demand. But unlike locational pricing, these options have limited potential to send a locational operational signal, meaning they are unlikely to significantly influence the real-time operation of the electricity market. Our and others' analysis suggests that a significant proportion of the system benefits of locational pricing come from the more efficient operation of the electricity system. Therefore, while some of these alternative options may carry less new risk for investors than locational pricing, the potential benefits for consumers are likely to be more limited.

The alternative options would likely need to be combined into a package to enhance their impact, including alongside wider reforms, for example, to the BM or settlement periods (explored further below) to also deliver operational benefits. As part of this, we will also assess what this package would mean for how risk is allocated between generators and consumers in a future electricity market design, and whether the package strikes the right balance between ensuring continued investor confidence and delivering efficient system operation.

In addition to the four options listed above, we have also considered whether we could add a locational element to our primary support schemes for electricity generation. The options we have considered are:

- Introducing a locational element to the CM (option E).
- Introducing a locational element to the CfD (option F).

We have decided to discount introducing a locational element to the Capacity Market, as it would likely have limited ability to alleviate constraints while introducing significant downside risk. We are also not minded to take forward adding a locational element to the CfD scheme as a primary option as part of the set of alternative options, however we may consider doing this in the future as a supporting change to other reforms in specific circumstances. Our rationale is explained in more detail below.

The alternative options we are considering are mostly – although not completely – mutually exclusive with locational pricing. For example, expanding constraint management measures could be implemented in both a zonal pricing and a national pricing scenario. It should also be noted that if we were to implement zonal pricing, then supporting changes would likely be needed in all the policy areas pertinent to these alternative options. This is discussed in the 'Design parameters for a GB zonal pricing model' section above (and Appendix 4), and in the Options Compatibility and Legacy Arrangements section.

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

Network charges are used by Ofgem to recover the costs of managing electricity networks. Ofgem are currently in the process of reforming network charging, to ensure that the approaches taken remain fit for purpose and align with REMA.

One of the charges Ofgem is reviewing is Transmission Network Use of System (TNUoS) charges. TNUoS charges are the annual charges used to recover the costs of the transmission network from both demand and generation, set two months prior to taking effect. TNUoS already sends a locational investment signal, as one component of the charge is broken down into 14 zones for demand and 27 zones for generation. However, the effectiveness of the investment signals sent by TNUoS is unclear at present. There are significant differences in the generation charge between locations, and this is expected to increase further in the coming years. However, the generation charges are also perceived to be volatile and hard to predict, making it challenging for market participants to respond to them in a considered manner.

Ofgem have reinstated the TNUoS taskforce, with the aim of considering near to medium-term improvements to charging arrangements, focusing on cost-reflectivity, stability, and predictability. The locational investment signals sent by TNUoS are currently considered to be broadly cost-reflective, however improving the stability of the charge may require a trade-off between cost-reflectivity and predictability. It is possible that some reform options could reduce the strength of the locational TNUoS signal, but equally possible that others enhance that signal. The taskforce has identified its priority areas for review, and Code Modification Proposals have already been raised in two areas, with further proposals to follow.

Alongside the TNUoS taskforce, Ofgem have also begun a longer-term strategic review of TNUoS, on which an open letter has recently been published.⁸⁷ This review will consider the role and design of transmission charging in the context of wider network and market reforms, including REMA, and the question of how best to send effective locational investment signals. Consideration will be given to how transmission charges could be designed to fairly recover network costs and effectively influence future generation, storage and demand investments and retirement and repowering decisions. Options include significant reform to the current methodology, for example system charges aiming to reflect the forecasted future planned network, rather than today's methodology of the current network. In the next phase of REMA, we will carefully consider how options for reform would interact with existing charging arrangements, in particular network charging discounts for Energy Intensive Industries.⁸⁸

 ⁸⁷ Ofgem, 2023, Open letter on strategic transmission charging reform. Available at: <u>https://www.ofgem.gov.uk/publications/open-letter-strategic-transmission-charging-reform</u>
 ⁸⁸ Department for Business and Trade, 2023, Government response: British Industry Supercharger Network

^{oo} Department for Business and Trade, 2023, Government response: British Industry Supercharger Network Charging Compensation Scheme. Available at: <u>https://www.gov.uk/government/consultations/british-industry-</u> <u>supercharger-network-charging-compensation-scheme/outcome/government-response-british-industry-</u> <u>supercharger-network-charging-compensation-scheme</u>

There are a number of requirements for transmission charging that have been retained from EU legislation. In particular, Ofgem's open letter on strategic transmission charging reform notes that annual average transmission charges paid by generators (subject to certain exceptions) must be within the range of €0-2.50/MWh ('the Permitted Range').⁸⁹ An adjustment is currently made to generation tariffs to ensure compliance with this range. Ofgem identified concerns that this adjustment has a material impact on the overall effectiveness of the transmission charging signal to generators. Alongside Ofgem, government will continue to assess the appropriateness for the Permitted Range, including consideration of whether it is consistent with the reforms proposed through REMA.

Ofgem is also reviewing Distribution Use of System (DUoS) charges. DUoS charges recover the cost of operating and maintaining the distribution system. Ofgem is at an early stage of scoping out issues with DUoS, in partnership with stakeholders. In the long-term, work could include reviewing the different signals sent at transmission and distribution level, and an investigation into potential improvements to the locational and temporal granularity of DUoS charges.

We will continue to consider options for reforms 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.

Option B: Reviewing Ofgem's transmission network access arrangements

Network access rights are a key feature of electricity market design as they determine the nature of a market participant's access to the electricity network and the network capacity they can use. GB transmission-connected market participants generally have financially firm access rights to the entire transmission network.⁹⁰ This form of financially firm access rights has contributed to rapidly escalating constraint management costs, which are set to increase even considering significant network expansion, as significant volumes of renewables connect to the constrained parts of the network.

In parallel with REMA, Ofgem is therefore considering how access reform within a national wholesale market could be used to improve locational investment and operational signals to bring down the costs of building and operating a high-renewables system. Access rights reform of this nature has been considered several times by Ofgem previously.

Changes to firm access rights have the potential to improve investment signals, e.g. by better incentivising new generation assets not to locate behind network constraints as they would face increased volume risk (i.e., the risk that the network cannot physically accommodate their traded position due to network constraints and they are not compensated for being asked to reduce their output). Ofgem is still exploring how far changes to access rights could impact operational decisions taken by assets. However, even if the removal of firm access does not change operational behaviour, total balancing costs in a national market could reduce as affected assets would no longer be compensated by ESO when curtailed.

⁸⁹ See The Electricity Network Codes and Guidelines (Markets and Trading) (Amendment) (EU Exit) Regulations 2019.

⁹⁰ This means they can submit any intended export/import position in real time, irrespective of whether this position is physically feasible for the transmission system and are eligible to receive compensation should their access rights be curtailed.

High-level options⁹¹ currently being assessed by Ofgem include:

- **Changing access rights for new assets**: This includes limiting firm access rights for new assets and then either auctioning or centrally allocating firm access rights for new assets. Under these options, existing users would retain their current firm access arrangements.
- Changing access rights for existing and new assets: This includes all transmission access rights becoming non-firm, with all assets only having firm access rights to their local area.

In their assessment, Ofgem is considering the interaction of access reform options with broader changes to the wholesale and balancing market arrangements, dispatch arrangements and investment support schemes. This is because changing access rights alone could negatively impact investor confidence and potentially give rise to a series of operational risks and challenges that could significantly reduce the benefits from such action. For these reasons, **changing access rights for existing assets would only be considered by Ofgem if introduced alongside more major REMA reforms**, specifically zonal pricing or central dispatch. More detail on the assessment of access reform options can be found in Appendix 4.

We will continue to consider options for reforms to access rights in the next phase of the REMA programme. As with option A on transmission charging reform, Ofgem and DESNZ have agreed to work on the programme of access rights reform to the same timeframes as the REMA process, to ensure that decisions on the two can be taken together, given the interlinkages.

Option C: Expanding measures for constraint management

We are also considering action to reduce the cost of constraints through specific constraints management measures, in some cases building upon those already undertaken by ESO.⁹² We have identified a number of options, some of which could be put in place in advance of any locational pricing reforms taking effect. These measures have been informed by extensive industry engagement as well as externally commissioned research. The options we are considering include:

- Expanded local constraints markets. ESO's relatively small-scale local constraints market in Scotland could be substantially built upon. This could include application to other parts of GB and coverage across a range of procurement timeframes. This option could potentially see significant levels of otherwise-curtailed energy being used productively for industrial purposes and applications like storage and electrolysis. The impact of constraints markets on liquidity will be considered.
- **Improved forecasting of congestion**. Better forecasting of future constraints would enable market participants to respond more effectively in advance of periods of network congestion. This could be important to the functioning of local constraint markets (as set out above), for example in planning flexibility services. It would be important to take

⁹¹ The potential options contain ranges of optionality within themselves, such as whether they would be enduring or transitional based on the progress on network build, and whether they would be static or dynamic (e.g. temporal or locational).

⁹² ESO has a 5-point plan for addressing network constraints which includes, inter alia, the Constraints Management Intertrip Services (CMIS) and small-scale Local Constraints Markets for non-Balancing Market assets.

account of any risk of gaming by market participants where more detailed forecasts are made available.

- **Storage-based solutions**. These could include, but may not be limited to, storage being deployed to free up more transmission capacity in congested points in the transmission network by reducing the need to set aside unutilised spare capacity for pre and post fault events, due to the ability of modern storage technology to absorb or release electricity rapidly.
- Before day-ahead constraint price signal designed to discourage generation in areas behind constraints at times of congestion. We will continue to explore options for signals that could mimic the effect of locational pricing to incentivise self-curtailment and avoid the level of change that would result from wider wholesale market reform. Further consideration is required of the form that this signal could take.

We will continue to consider all of the above options in the next phase of REMA. We believe that these options could operate in synergy with other options and in some cases could be delivered ahead of any potential move to locational pricing. Limited cost-benefit impact has been undertaken for these options so far but there could be potential for lower balancing costs, including by reducing the volume of constrained electricity behind constraints and the cost of turning up energy in front of them, although the scale of these savings is as yet unclear. The first three options above could potentially open new revenue streams for investors and generators of a range of capacities in a range of constraint management opportunities, both in front of and behind the constraint.

Option D: Optimising the use of cross-border interconnectors

Interconnectors have recently and will continue to make up a significant proportion of GB's electricity capacity. As explained above, one of the potentially more significant benefits of locational pricing is supporting the more efficient operation of interconnectors. Currently, interconnectors can, at times, flow energy in directions counter to GB system needs. This means energy is being exported from locations in GB where more generation is needed (i.e. South of England) and imported into areas where generation cannot be transported to the rest of GB due to network constraints (i.e. Scotland). Introducing more efficient locational signals in GB could mean the direction of interconnector flows is more reflective of GB system needs.

Given the significant role of interconnectors in the GB energy system and the potential system benefit of locational pricing for interconnectors, we must also consider how we could deliver some of these benefits under a national pricing scenario. This is an important part of our work to develop a package of alternatives to locational pricing which can suitably address the scale of issues identified in this challenge, including maximising the benefits of low carbon flexibility.

The ESO is already undertaking work in this area. This includes improving the efficiency of existing interconnector redispatch and SO-to-SO trading processes.

The ESO is also assessing options to enable the exchange of balancing products between the EU and UK. Following EU-Exit, GB can no longer participate in the EU internal market for energy, and in particular cross-border balancing platforms such as TERRE and MARI. The ESO commissioned external consultants to undertake this assessment of options and the results of their work were shared earlier this year.⁹³ Some of the options considered included introducing an EU-GB cross-border balancing platform which would operate separately to

⁹³ ESO, 2023, Cross Border Balancing Webinar. Available at: <u>https://www.nationalgrideso.com/calendar/cross-</u> border-balancing-webinar

cross-EU platforms and allowing EU SOs and ESO to directly exchange balancing products with each other. All options assessed presented some drawbacks and/or operational difficulties, although some were deemed more promising than others. We will work closely with ESO to assess options in the future and will ensure this work closely aligns with any other changes introduced through REMA.

Overall, in the next phase of REMA, we will continue to work closely with ESO/NESO, Ofgem and other stakeholders to identify and assess potential options and assess the level of benefits which could be delivered under a national pricing scenario. This will include building on work which is already underway as well as identifying new options. In this work, we will always take into account our international trading obligations for energy trading and cooperation, including those in the UK and EU Trade and Cooperation Agreement.

Option E: Introduce a locational element to the Capacity Market

Introducing a locational element to the CM could in theory incentivise new build generation assets securing CM agreements to locate in import-constrained parts of the network. We have looked at evidence from CM auctions and model output data, as well as international examples and academic literature, to assess the benefits and risks of a locational CM if it were to be implemented in GB.

The CM could be reformed to reward generation locating in import-constrained regions (in the case of auctions for specific zones) or help incentivise optimal location through bid multipliers or derating factors. However, a locational CM could increase costs, e.g. as smaller locational pots could reduce liquidity and competition within the auction. In addition, some respondents to the first REMA consultation expressed concerns that adding locational elements to the CM could unnecessarily increase complexity.

Internal analysis suggests this option would likely have limited ability to alleviate constraints, particularly as the CM tends to be dominated by existing capacity. When coupled with potential increases to the cost and complexity of the CM, we have decided to discount introducing a locational element to the CM as a standalone option.

Option F: Introduce a locational element to the CfD

Amending CfD auction design to account for location could theoretically provide a locational investment signal for renewable generation and reduce the contribution renewables make to network constraints.

There are challenges in how to design such an option to send an effective locational signal. While it could provide a clear and consistent signal over a long period of time, it would be important to ensure that any increased cost to consumers in incentivising location in certain areas is justified by the potential system benefits. This is complicated by the CfD allocation process coming relatively late in the renewable development timeline, following locational decisions being made based on a variety of other factors such as resource availability or the local planning or consenting regime.

We acknowledge that this option alone is not likely to provide a means of sending costeffective locational investment signals. However, adjusting the CfD to account for location could complement and have synergies with other REMA options and more widely for sending locational signals under national pricing, such as network charging reform, reviewing transmission network access arrangements, and more strategic energy spatial planning. For example, if TNUoS reforms were to significantly increase locational differentials, this could increase CfD strike prices more generally (increasing consumer costs); changes to the allocation framework could mitigate this (e.g. different locational pots), though this would need to be considered alongside potential liquidity impacts. In Challenge 2, we set out options to evolve the CfD. Some variations of these options may have the potential to send a locational signal. The design of and decisions on these options may therefore influence the risks and benefits of additionally modifying the CfD allocation process locationally. It should be noted that we are considering how a future-proofed CfD could be designed to complement and synergise with zonal pricing – this is discussed further in the Options Compatibility and Legacy Arrangements section.

We are not therefore continuing to develop the option of introducing a locational element to the CfD allocation process as a primary option for sending locational investment signals. However, we will pay due consideration to the design of the CfD and its allocation process with respect to reforms in other areas.

Question:

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

Improving temporal signals

Increases in intermittent generation, rising electricity demand, and the development of new technologies 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. REMA has considered two options to improve temporal signals:

- **Option 1 Settlement periods:** One factor that could be limiting the scope for flexibility is that market participants trade in units of no less than 30 minutes, reflecting the current Imbalance Settlement Period (ISP) duration. The ISP is the period over which market participants are held accountable for any imbalances between their contracted and physical positions. Market prices are therefore uniform across each 30-minute period, which is arguably insufficiently granular with respect to the changes in supply and demand that might take place within a given period. This may deny opportunities to market participants that are able to act flexibly, in response to sudden price movements.
- Option 2 Gate closure: Another blocker to temporal flexibility is arguably the 60minute 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 must keep to the positions indicated in FPNs denies them the opportunity to make adjustments closer to real-time, on the basis of the latest information.

The previous REMA consultation also discussed how on the demand-side the way that policy costs (such as CfD and CM costs), and network costs are passed through to consumers dampens temporal signals, limiting the ability of suppliers to provide tariffs that incentivise flexible behaviour from consumers.

With the decline of fossil fuel-based generation and the growth of renewable generation with high capital costs but low short-run marginal costs, wholesale market costs will make up a declining proportion of suppliers' costs and consumers' bills over time. The implications this could have for pricing signals for flexibility and demand side response will continue to be considered, as part of our parallel programme of actions to reform retail energy markets.

Option 1: Shorter settlement periods

Shortening the 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 DSR assets, and reduce overall costs by moving volumes out of the Balancing Mechanism and into the wholesale market.

Any decision to shorten ISPs will require a careful consideration of the likely costs and benefits, with costs associated with changes to metering and notification systems likely to be significant. 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. We will therefore continue to consider this option and the potential interactions with other potential reforms.

Option 2: Tighter Gate Closure

Tightening the Gate Closure interval (e.g. to 30 minutes) would support all BM unit parties to base their FPNs on information which is closer to real-time. This could facilitate more accurate supplier and generator forecasting, and support market participants to trade out of imbalance. It is difficult to estimate the scale of any potential benefits at this stage.

However, tightening Gate Closure could reduce the ESO's ability to balance the system efficiently and economically and may have security and safety implications. The Gate Closure interval is currently vital for the ESO to manage congestion, and deal with other operational considerations that market participants are not incentivised to respond to, such as inertia.

Our view is that tighter Gate Closure is not something that could be implemented in the shortto medium-term but could form part of longer-term market design beyond REMA. **We are therefore discounting it as part of the REMA package of reform.**

Improving balancing and ancillary services

As well as introducing new challenges in managing locational constraints, the emerging system is raising challenges in balancing the system across several other operational requirements. More variable sources of generation and demand, coupled with less dispatchable or synchronous generation which can offer system services such as voltage, stability, and inertia is making it more difficult for the ESO to balance the system efficiently and cost-effectively. Below we explore options to help improve system balancing and improve the operational efficiency of the market, in addition to the actions set out in the <u>2021 Smart Systems and Flexibility Plan</u>.

Balancing Mechanism reform

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.

As discussed in the introduction to this section, the ESO is facing a number of high-level challenges when it comes to balancing the system. There are at least three issues with the current arrangements:

- 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.
- The BM is increasingly being used to implicitly co-optimise across a range of operational needs (e.g. 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.
- 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.

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, to enable greater participation and widen access to more low carbon and demand side participants.

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 we have provided a more detailed description of each of these and, if applicable, a summary of the work already underway which might help address them.

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.

Centralised dispatch

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.

In this context, dispatch refers to two activities:

- Determining and refining the operational schedule.
- Issuing real-time dispatch instructions to generators.

Self-dispatch markets try to maximise the scope for market participant decision making, reducing the role of the System Operator before Gate Closure. Contracted positions – arrived at in a decentralised fashion – feed directly into dispatch decisions, which generators are free to make for themselves. The System Operator then corrects the market outcome via 'redispatch' (e.g. in the Balancing Mechanism) to ensure a balanced system.

By contrast, centralised markets try to coordinate assets and System Operator requirements prior to Gate Closure via a centralised auction, for example at the day-ahead stage. Only contracted positions arrived at via the centralised auction feed directly into the dispatch process.

Centralised nodal markets (e.g. across the US, and in New Zealand) can also give generators the option to 'self-schedule' (or 'self-commit') their own units. While only the System Operator can issue dispatch instructions, generators are compensated for deviations from these scheduled positions. One option would be to include 'self-commitment' in a national or zonal pricing centralised dispatch model, perhaps allowing for a 'middle ground' between self-dispatch and centralised dispatch.

Centralised dispatch could be implemented either alongside zonal pricing, or as a standalone option.

On the one hand, centralised dispatch may have benefits when it comes to optimising dispatch across multiple settlement periods. The ESO is currently using the BM to do so, but as this was not its intended function this may be leading to excessive costs. This could become more problematic as more renewable generation comes online and redispatch volumes increase, especially given the issues with the BM outlined above.

Centralised dispatch may have benefits when it comes to competition, participation and 'cooptimisation' across multiple balancing services. The potential for 'co-optimisation' in particular could improve liquidity by bringing multiple markets together.

On the other hand, decentralised markets are thought to better facilitate hedging and intra-day adjustments to developing system conditions, among other benefits. It may also be possible to address deficiencies in the BM via increased day-ahead procurement, and more trading actions.

Any transition to centralised dispatch would likely 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 any market disruption.

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. The ESO will be publishing results in spring 2024.

We will therefore continue to consider different designs of central dispatch as part of the next phase of REMA.

Additional measures to maintain operability in a decarbonised electricity system cost effectively

In the previous REMA consultation, we sought views on options specifically for promoting efficiency and investment in low carbon ancillary services for meeting the needs of a system increasingly dominated by variable renewable energy, including whether a business-as-usual approach would be sufficient. We have concluded, in the light of evidence supplied by stakeholders, that existing and planned policies will need to be strengthened, irrespective of broader wholesale market reform. We have refined the options that were set out in the first consultation and are consulting on making the following reforms:

- An electricity system operability strategy for 2035. This will set out a course for how system operability can be maintained in a way that is consistent with the government's 2035 decarbonisation commitment, at best value to the consumer. We intend this to be published by NESO.⁹⁴ The strategy would give industry greater clarity on the approach to be taken by the system operator to helping ensure that the government's 2035 target is met. While NESO will not be able to achieve decarbonisation of system operation on its own, it will have important enabling levers, including its procurement policies.⁹⁵ We would work with ESO/NESO, Ofgem and stakeholders to develop this strategy.
- ESO/NESO to improve forecasting of medium to long-term operability needs, including by location where relevant. This will help give investors and developers the level of certainty that they need for the future demand of these services to invest in low carbon ancillary service capability.
- Improved greenhouse gas emissions reporting on ESO/NESO operability activity across all electricity markets.^{96,97} This could potentially include data on both carbon intensity and tonnes of carbon emitted by action type, for example for constraints management, reserve, and inertia.

In addition, we will continue to consider the need for reform in other aspects of operability as described below:

Exploring perceived barriers to the provision of ancillary services from co-located assets. Stakeholders have raised concerns about barriers to the high potential for the provision of low carbon ancillary services from assets co-located with renewable generation (such as storage, and electrolysis) due to factors including metering arrangements and the asset ownership rules under the Offshore Transmission Owners (OFTO) regime. We will continue to investigate the need for reform in the case of these perceived barriers.⁹⁸

⁹⁴ NESO will build on the functions and capabilities of the current ESO. Depending on a number of factors, including agreeing timelines with key parties, our aim is for NESO to be operational in 2024.

⁹⁵ For example, the introduction of ESO's stability pathfinders has the potential to reduce reliance on gas-fired generators for system inertia and reduce carbon emissions.

⁹⁶ ESO already makes data available on the overall carbon intensity of balancing actions and on its ability to operate a zero-carbon system.

⁹⁷ This builds on action 3.6 set out in the 2021 Smart Systems and Flexibility Plan.

⁹⁸ Greater clarity on metering arrangements for co-located assets in CfD supported schemes was provided by LCCC in its updated CfD Co-location Generator Guidance in March 2023:

www.lowcarboncontracts.uk/resources/guidance-and-publications/cfd-co-location-generator-guidance/.

• Alignment of 'longer term' ancillary services with CfD and CM auctions. There was strong support from stakeholders for aligning CfD and CM auctions with those for ancillary services to provide more revenue visibility to providers to aid and inform their investment planning. We are considering how a practical way of achieving this could be undertaken. For a limited number of 'longer term' contracts which are awarded further ahead of delivery, there could be scope to move closer to timing of CM and CfD auctions. We will continue to explore the scope for better alignment with NESO and other stakeholders.

We believe that these options, taken together with other options we are considering in REMA, would help to provide confidence that a fully decarbonised electricity system can be achieved by 2035 cost-effectively, subject to security of supply. While we recognise that work will need to be undertaken with stakeholders to develop these proposals further, we would anticipate that they can be implemented in a relatively short timeframe.

We will not however be taking forward some of the other options in the first consultation further as part of REMA, as they are already being addressed or we consider them not to be feasible at the current time:

- In the previous REMA consultation, we consulted on the benefits of a matrix approach to ancillary service procurement in which providers can submit linked bids for ancillary services that can only be delivered together. We consider that the benefits of matrix procurement will be effectively provided through the ESO's Enduring Auction Capability (EAC) which will enable a substantial degree of co-optimisation⁹⁹ within ancillary services.¹⁰⁰
- In the first consultation, we sought views on a requirement for the ESO to strike an
 optimal balance between long and short-term contracts for ancillary services,
 recognising the scope for greater competition close to real time, while investment for
 some assets depends on long-term contracts. On further examination, it has become
 apparent that the practicality of defining an optimal balance would be of questionable
 value due to the number of variables involved and rapid rates at which markets evolve.
 ESO has set out principles for its procurement policies which it will continue to follow.¹⁰¹

We had considered an option for giving the ESO or NESO the **ability (or an obligation) to prioritise zero/low carbon procurement**. We currently consider that exercising this ability or complying with a specific obligation of this nature could be excessively complex and might inhibit the ability of the system operator to operate the system efficiently. Moreover, NESO will be required to carry out its functions in a way that it considers is best calculated to promote its objectives, which includes enabling the delivery of net zero as part of its general duties under

The government recently consulted on proposed amendments to CfD for AR7 and future rounds:

https://www.gov.uk/government/consultations/proposed-amendments-to-contracts-for-difference-for-allocationround-7-and-future-rounds (scheduled to open for applications in 2025) and beyond, including introducing new hybrid metering arrangements for CfD generation co-located with other assets, which could support increased provision of flexibility and ancillary services. The government recently published a call for evidence on the OFTO regime on 13 November 2023: www.gov.uk/government/calls-for-evidence/offshore-transmission-owner-oftoregime

⁹⁹ This is distinct from co-optimisation between energy and ancillary services which would require central dispatch.

¹⁰⁰ Assets will be able to offer to the EAC multiple frequency response and reserve ancillary services; a market clearing algorithm then allocates each unit to the 'optimal' service.

¹⁰¹ ESO outlines the principles with which they assess whether to procure short vs long-term in their market design framework documents: <u>www.nationalgrideso.com/research-and-publications/markets-roadmap.</u>

the Energy Act 2023.¹⁰² We are therefore not currently proposing to give ESO or NESO an obligation to prioritise zero/low carbon procurement.

In the first consultation we sought views on an expanded role in the operability of networks at a local level, which could include a greater role for DNOs in managing operability. Since the publication of this consultation, Ofgem have carried out a review into local governance arrangements and in November 2023¹⁰³ set out their decision to introduce a new regional energy strategic planner role and assign a market facilitation function to a single entity to deliver more accessible, transparent and coordinated flexibility markets. DNOs will remain responsible for real-time operations and Ofgem set out their expectation for them to continue developing their DSO capabilities. In addition, the work under the Energy Network Association's (ENA) Open Networks project continues to be critical to improve DNO/NESO coordination and facilitate open and accessible markets to unlock the full value of flexibility being offered. Due to the progress made in this area since the first consultation, we will no longer be considering this as a stand-alone REMA option. Instead, we will progress this through our ongoing work overseeing the implementation of actions in the 2021 Smart Systems and Flexibility Plan in order to improve coordination across the national and local levels, creating a clearer route to market, ultimately increasing investor confidence, and promoting whole-system flexibility.

More detail on how we have evolved and refined the options on operability from the first REMA consultation are set out in Table A4.9 in Appendix 4.

Question:

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

Improving local and national co-ordination

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.

Government is progressing the actions set out in the 2021 Smart Systems and Flexibility Plan to accelerate the deployment of low carbon flexibility in the 2020s, by sharpening signals for flexibility and removing barriers to entry within the current market framework.

This includes a step change in coordination between distribution and transmission systems, for example through the development of primacy rules. Through REMA we are considering what further actions are needed in order to deliver open, dynamic and coordinated markets for distributed low carbon flexibility (see Challenge 3). Sharpening signals will incentivise investment by creating opportunities for market participants to earn revenue and be rewarded

¹⁰² Under the Energy Act 2023, NESO must carry out its functions in the way that it considers is best calculated to promote the Government's net zero duty, ensuring security of supply and promoting efficiency and economy of the electricity and gas systems.

¹⁰³ Ofgem, 2023, Future of local energy institutions and governance. Available at: <u>www.ofgem.gov.uk/publications/consultation-future-local-energy-institutions-and-governance.</u>

for the system services they can provide. Many of the options set out in this section could help to strengthen these signals. In the previous consultation we considered a specific option – local wholesale markets – that we are no longer taking forward.

Local wholesale markets

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.

However, supported by external research, **we have decided to discount this option** as there are significant uncertainties around the cost and benefits of the 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.

Liquidity in the wholesale market

Background

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 (both referred to as 'physical' traders) and intermediaries (known as 'non-physical' 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 price differentials. Some physical traders also make non-physical trades, 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 during 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 eased 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 more weatherdependent renewable generation which is harder to forecast far in advance and the current design of the CfD, which is based on a day-ahead reference price. The CfD is designed to remove 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 could reduce forward market liquidity as it reduces the number of generators participating in this segment of the market. However, suppliers still need liquid forward markets in order to manage their risk through hedging, and 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 Secure and Promote Market Making Obligation (S&P MMO). There have also been 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.

Ofgem published a call for input at the end of last year¹⁰⁴ 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 FTRs – and have been applied in other markets internationally. Even with mitigations in place, there is still a risk of negative impacts on liquidity during a transition to locational

¹⁰⁴ Ofgem, 2023, Call for input: power market liquidity. Available at: <u>https://www.ofgem.gov.uk/publications/call-input-power-market-liquidity.</u>

pricing, due to the significant 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 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 strike prices, making the CfD scheme more expensive for consumers. Challenge 2 discusses options for reforming the CfD reference price methodology in more detail.
- **Central dispatch**. This measure could reduce or increase liquidity depending on design. It could have a positive impact on liquidity in short-term markets, as transactions are pooled centrally. However, allowing self-commitment (which has other benefits) could result in liquidity being split and therefore reduced. As with 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.

Conclusions and next steps

A range of reforms to wholesale markets and balancing arrangements in GB will be required as we move to a decarbonised electricity system. This section has discussed our latest thinking on these challenges, how we have narrowed down the options, and where further analysis and evidence gathering is required.

In this section we have proposed to:

- Continue to consider strengthening locational signals in the market by assessing two sets of options – locational pricing in the form of zonal pricing, which would send wholesale market participants both locational investment and operational signals – alongside a set of alternative options which would operate under national pricing to improve locational signals which primarily send locational investment signals. This includes working with Ofgem on reforms to network charging and transmission access in parallel with REMA reforms.
- Discount nodal pricing due to the impacts it would have on investor confidence and the deliverability of our 2035 decarbonisation targets.

- Continue to consider centralised dispatch, alongside the option of a reformed Balancing Mechanism. We will also continue to consider other reforms to existing arrangements such as shorter settlement periods.
- Work with ESO, Ofgem and wider stakeholders to develop proposals for an electricity system operability strategy for 2035, better forecasting of operability needs and improved emissions reporting by ESO/NESO. We will also investigate perceived barriers to the provision of ancillary services from co-located assets and how alignment of 'longer term' ancillary services with CfD and CM auctions could be achieved.
- Discount the 'local markets' model, which aimed to reorient the wholesale market around local, distribution-level markets. Instead, we will continue to consider what further actions are needed in order to deliver open, dynamic and coordinated markets for distributed low carbon flexibility as discussed in Challenge 3.
- Continue to consider the impacts of REMA reform on market liquidity.

In the next phase of REMA, we will work closely with Ofgem, ESO/NESO and industry to develop market designs under both national and zonal pricing scenarios, to enable us to assess and compare the benefits of each design. As part of this, we will assess both benefits and risks, as well as how well they tackle the emerging and longer-term issues we have identified.

As set out in Challenge 2, the chosen wholesale market arrangements will have to work seamlessly with future CfD reform options. A particular focus for the next phase of REMA will therefore be to consider how CfD and wholesale market reforms might act in combination to distribute in different ways risks, benefits, and costs across market participants and technologies. In the next phase of REMA, we will therefore need to consider the optimal overall system design and then take final decisions on the remaining policy options, guided by that overall system perspective.

We will also work closely with ESO and Ofgem to build on the Smart Systems and Flexibility Plan to further develop and take forward shorter-term no regret options that would be required under either approach that would improve system operation in the near-term.

Options Compatibility and Legacy Arrangements

Section summary

Electricity markets are part of a complex system with many components and interactions. This section sets out REMA's initial assessment of the interactions and compatibility between the various policy choices to assess how they would affect market participants and investors.

The section first considers option compatibility, including where options are incompatible and cannot coexist, and where options are compatible but have interactions - either positive or negative. This concludes that there is a high degree of compatibility between the remaining REMA reform options.

The section also explores major policy options which are compatible, but where the interactions between options are likely to be most complex. Any changes to wholesale market design, in particular a move to locational pricing (the merits of which are explored in Challenge 4), would have significant impacts on electricity markets and policies. The interaction between locational pricing and government support scheme design will be key. Views are sought on our initial assessment of compatibility and key interactions between remaining options, and if there is anything else that should be considered.

In addition to the forward-looking assessment of reform options compatibility, the section also sets out a proposed approach for considering and managing the impact of REMA reforms on legacy assets and arrangements.

Introduction

Electricity markets have strong interactions with each other. There are **direct links** between markets; for example, the existing CfD scheme uses the wholesale market as the reference price in the contract. There are also **indirect links**; for example, assets can compete in multiple markets, and will decide which markets to enter based on the relative profitability of each. This means that reforms to one market will have consequences for other markets.

Developing a whole-system assessment is therefore important to identify the best arrangements for a renewables-dominated electricity system (and the transition to it). It allows us to identify the detailed policy choices that determine the allocation of risk between market participants, and how reforms affect previous commitments. Different policy options and choices will affect this risk allocation in different ways, and future market design will need to balance any changes to risk allocation (where this is beneficial for system operation) with delivering continued confidence and stability for market participants and investors. This will be a central consideration in the next phase of our assessment.

In the following sections we split our assessment into a forward-looking element, and a backwards looking element. 'Options compatibility' is a forward-looking assessment of how the remaining REMA reform options interact with each other. 'Legacy Arrangements' is a

backwards-looking assessment of how REMA reform options impact Legacy Assets and Legacy Arrangements.

When considering the case for different REMA options, we are considering both:

- the overall impacts that REMA options may have on existing assets and market participants; and
- whether there is a case for providing proportionate protection for some existing assets and participants from reform options.

Options Compatibility and interactions

REMA is ultimately aiming to deliver a set of reforms which result in a comprehensive and effective electricity market design. As part of this phase of the REMA programme, we have therefore carried out an initial assessment of option compatibility:

- **Strict compatibility** options are incompatible where they could not be implemented together. This could be because they are duplicative, or because they would send inconsistent signals to market participants.
- Interacting mechanisms even when two options are compatible there will still be interactions between them, which could be positive (where one option improves the effectiveness of another) or negative (where one options limits the benefits of another).

Assessment - our initial conclusions on option compatibility

Our assessment suggests there is a high degree of compatibility between the remaining REMA reform options.

There are some options where there is incompatibility between design choices. For example, a move to central dispatch would rule out self-dispatch and would fundamentally change the role of the Balancing Mechanism. Similarly, a move to locational wholesale pricing would have implications for the extent and nature of reforms to other market-based locational signals such as network access and charging arrangements.

Our initial view is that locational pricing and wholesale market design, including dispatch arrangements, are likely to have the most complex and impactful interactions with wider market design. However, whilst we have sought to set out the most salient interactions below to support whole-system decision making and understanding of trade-offs, this is not intended to be exhaustive, and we will look to conduct a fuller assessment of interactions in the next phase of options assessment.

Changes to wholesale market design

Any move to locational pricing, changes to dispatch, settlement and balancing arrangements would have significant impact on, and interactions with, a wide range of policies and markets.

Shortening settlement periods (e.g. to 5 or 15 minutes, as opposed to the current 30 minutes) would significantly increase the temporal granularity in the wholesale market, providing greater incentives for both supply- and demand-side flexibility, and potentially rewarding more

responsive behaviour from CfD-supported assets in combination with changes to CfD risk allocation (e.g. through implementation of a capacity-based CfD model).

Centralised dispatch would represent a particularly significant change from the current selfdispatch market. Self-dispatch markets try to maximise the scope for market participant decision making. By contrast, centralised dispatch markets try to coordinate assets and System Operator (SO) requirements prior to gate closure.

For central dispatch, the main interaction with the CfD reform options is likely to be when subsidy payment is linked to output. In current market arrangements assets that are turned down due to network constraints are compensated for their lost revenue in the Balancing Mechanism. This payment may be fully or partly removed under central dispatch. However, our initial assessment suggests that changes to the design of support schemes could mitigate the additional volume risk. In some central dispatch markets, the SO would first run an 'unconstrained' output, which indicates market clearing in absence of system constraints. If support payments were linked to this unconstrained output, rather than metered output, the volume risk faced by renewable assets would be similar to that in a national pricing market.

Further policy development is needed to confirm the detailed interaction between wholesale market design, support schemes, and market participants. Of particular note, however, is the interaction between locational pricing and CfD design which is explored further below.

Locational wholesale pricing and renewables support schemes

Locational wholesale pricing is likely to have particularly significant impacts on, and interactions with, reform to renewables support schemes. A key consideration is how far investors are exposed to locational risks. Exposing investors to locational risks should maximise the benefits of locational signals, but placing these risks excessively on investors could increase the cost of capital – so the trade-off needs to be considered carefully.

We consider the two risks that locational wholesale pricing would introduce for CfD-supported assets:

- Locational price risk is the degree to which investors are exposed to changes in the value of the locational signal. In the case of locational pricing, this is the difference between the local price and system average price. In the current market there is no locational price risk as all generators receive the same price, although network charges (TNUoS and DUoS) vary by location.
- Locational volume risk is the degree to which investors are exposed to the network not being able to physically accommodate their power. In current market arrangements, assets are protected from locational volume risk because when they are turned down due to network constraints, they are compensated for their lost revenue in the Balancing Mechanism (The CfD negative pricing rule has however introduced some volume risk for generators with more recent CfD contracts albeit this is not currently locational). In a locational pricing scenario, depending on design, generators would not always be compensated when they cannot generate due to network constraints introducing new volume risks.

How these locational risks are allocated is dependent on design choices in the CfD reform options:

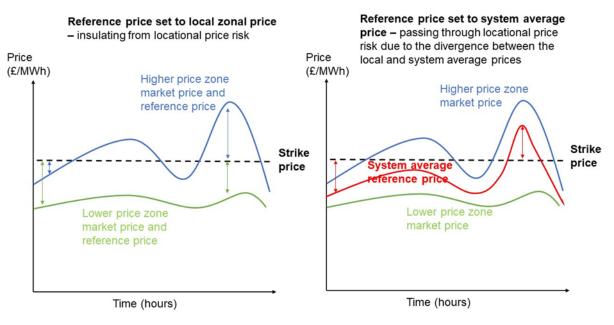
- **Reference Price** the wholesale market price for which the CfD 'top-up' payment is calculated against. Currently the IMRP is the hourly day-ahead national price.
- **Negative Pricing Rule** the rule determines whether CfD generators are paid their 'top-up' payment when wholesale prices are low. The current negative pricing rule stops the top-up payment when the IMRP is negative.

Changes to auction design would also then need to be made depending on the design of the CfD to determine how generators' bids are ranked in the auction and which projects are allocated a contract.

Reference Price

A CfD reference price based on the system average price would pass through the locational price risk to generators. As generators will sell at their local wholesale price, a reference price based on the system average, leads to assets in higher priced areas to receive higher revenues, but would mean that assets in lower priced areas would receive lower overall revenues. A reference price based on a local price blunts locational price signals as generators are no longer exposed to the risk that prices during the reference period deviate from the prices used to set the reference. This means all price risk for the duration of the contract is removed.

Figure 9: Diagram illustrating how pass-through of locational price risk is affected by choice of reference price¹⁰⁵



Negative Pricing Rule

Locational volume risk is introduced through the loss of firm access rights across zones under locational pricing. The negative price rule could affect how locational volume risk is distributed between assets. This is because the negative pricing rule affects the generator's place in the merit order, and, therefore, the frequency of it being constrained.

¹⁰⁵ Frontier Economics and Cornwall Insight, 2023, Market Signals and Renewable Investment Behaviour. Available at: <u>https://assets.publishing.service.gov.uk/media/65e5a4372f2b3bbc587cd78c/6-frontier-cornwall-insights-market-signals-renewable-investment-behaviour.pdf.</u>

- For a **CfD based on metered output**, a negative pricing rule based on the local price would pass through locational volume risk. This is because the CfD generators would not receive a support payment during periods of negative pricing in their local zone.
- In the **deemed CfD**, as the 'top-up' is paid on deemed output, completely eliminating the negative pricing rule would insulate generators from locational volume risk. This is because when generators cannot run due to network constraints, they would still receive a support payment based on their deemed output. Further work is needed to assess whether locational volume risk could be passed through in a deemed CfD with the introduction of a low pricing rule, or through administratively removing payments during periods of constraints more detail is contained within Challenge 2.

A **capacity-based CfD** model would be compatible with locational pricing. This option would expose generators to both locational price and locational volume risk, whilst still offering some degree of revenue certainty through the capacity payment. The siting decision of renewable assets would change their expected wholesale market revenue (e.g. those in higher priced or less constrained areas would earn greater revenue). We therefore expect that locational signals could be passed through in a capacity-based CfD auction as those with higher wholesale market expectations would need a lower capacity payment to meet their required return, and therefore be more competitive at auction. Further work is needed to consider how including a 'consumer protection' mechanism as part of the option would change assets exposure to locational risks.

Locational wholesale pricing and other investment support schemes

A locational wholesale price would also impact assets that participate in the CM and bespoke low carbon flexibility investment support schemes. These schemes are likely to expose assets to both locational price and volume risk, although the exact exposure will depend on the detailed design of each scheme.

We would expect assets in higher priced wholesale areas to capture higher wholesale market revenue. They would, therefore, need less support scheme revenue to ensure the required rate of return on investment. These assets would be able to bid more competitively and have a higher likelihood of winning a support contract. This means competitive support schemes should be able to pass through the locational signals from the wholesale market.

We are keen to understand stakeholder views on the options compatibility and interactions discussed throughout this section and the appropriate allocation of risks:

Questions:

- 25. Which market actors (e.g. generators, suppliers, consumers, government) are best placed to bear / manage different types of risk?
- 26. Do you agree with our initial assessment of the compatibility between our remaining options? Please set out any key interactions we have missed.

Legacy Arrangements

In this section, the following definitions are used:

- Schemes established by the government to incentivise the development of low carbon electricity generation or to ensure security of supply are referred to as **Government Support Schemes**.
- Arrangements under Government Support Schemes agreed prior to a published government position on REMA reforms are referred to as Legacy Arrangements.
- Assets that are the subject of these arrangements are referred to as Legacy Assets.

REMA reforms seek to optimise our future electricity market arrangements to minimise system costs and maximise consumer benefits. As outlined in the Introduction, the risks for different types of market participants associated with different reforms will need to be carefully assessed as part of the decision-making process in the next stage.

In doing this we will need to consider both how future arrangements will work but also how existing contractual arrangements (including those agreed before a public decision on REMA) will be affected (i.e. how existing arrangements will coexist alongside new arrangements). Changes may also be required to ensure that existing contracts and agreements work functionally in the event of certain reform options being taken forward.

At the same time, providing proportionate protection for Legacy Arrangements may affect the benefits case for future reform options. For example, protecting expectations for Legacy Assets may dampen the applicability of and/or strength of signals introduced by REMA reforms for market participants. This could reduce the system benefits associated with reform, reducing consumer savings.

We believe there are two broad categories of effect that we must consider:

- Functional effects contracts and schemes may rely on elements of current market arrangements to practically work e.g. use of market reference prices. Should these features change then existing contracts or schemes are likely to need to change to remain functional.
- **Financial effects** market changes may affect, for example, assets' revenue, price, volume and level of risk.

It will also be important to consider **timings** as REMA may impact on or require different mitigation actions depending on whether a contract is already in place or is agreed between now and when a REMA decision is made. As set out below, we would need to assess the case for and justify any difference in treatment between parties under the same Legacy Arrangement.

Our proposed approach

Each remaining REMA reform option and the range of Legacy Arrangements are distinct and could interact with each other in different ways. We therefore propose to assess REMA reform options and their impacts on a scheme-by-scheme basis – i.e. to consider, in turn and distinctly from each other (rather than taking a blanket approach).

In the next stage of REMA, we will consider the risks remaining REMA reform options may create for participants and Legacy Assets that have agreements in place in respect of the Legacy Arrangements described below. This is necessary to ensure that due consideration is given to whether protection is necessary and/or proportionate.

The range of arrangements and participants that may be affected by REMA reforms is broad. Participation in wholesale electricity markets relies on contracts between parties to sell/purchase electricity (a physical trade), on financial instruments to help hedge against the risks of buying/selling electricity, and contracts to secure investment in a project. Many of these contracts are between private parties. In addition, some parties benefit from support of one kind or another with Government Support Schemes.

Whilst REMA may impact a wide range of arrangements, the purpose of this chapter is to explore how Legacy Arrangements and Legacy Assets (and participants related to these arrangements) may be impacted and how new risks may be mitigated. Therefore, we are specifically considering the impacts of REMA reform options in respect of the following Legacy Arrangements: the Contract for Difference, Capacity Market, Renewables Obligation, Feed-in-Tariffs, Net Zero Hydrogen Fund, Interconnector cap and floor arrangements, and Nuclear CfD and RAB mechanisms. We will also consider government schemes currently in development, including those with no existing contracts in place, but which may be allocated before a REMA decision, e.g. offshore hybrid assets, the planned hydrogen business models for production, transport and storage, Power BECCS, Power CCUS Dispatchable Power Agreement (DPA), Long duration electricity storage and potential Hydrogen to Power business model.

As discussed throughout this consultation, in the next stage of REMA generally we will consider the impact of potential REMA reforms on different types of electricity consumers, including risks that may be introduced and mitigations that may be appropriate. For example, as discussed in Challenge 4 regarding locational pricing, any potential move to this would be introduced carefully to give electricity consumers time to adjust and enable adequate protections to be put in place where appropriate. Interactions with existing Government schemes that protect some electricity consumers (whether domestic or non-domestic /industrial) would also need to be carefully managed.

Managing impacts on CfD contracts

Whilst we are committed to further work on the impacts on Legacy Arrangements of all REMA proposals, to date we have completed more detailed assessment of the impacts locational pricing may have on CfD contracts. Our initial assessment is that locational pricing creates both new functional and revenue impacts for existing CfD contracts. (Note – centralised dispatch as a stand-alone option could also have an impact on CfD contracts. We will continue to consider this matter in the next phase of work.)

Existing CfD contracts currently utilise a reference price based on the national wholesale market, which would no longer exist under zonal pricing. According to the terms of existing contracts, a move to a zonal market would be likely to trigger an amendment to the contract so that the reference price is based on the market into which generators will sell their power i.e. the local, zonal market. CfD contracts on existing terms signed (those signed before the government publishes a decision on REMA reforms) would, therefore, be capable of amendment to reflect a local reference price. This would ensure legacy CfD holders still achieve their strike price when they generate and are insulated from locational price risk for the duration of their contract. The contract terms which prescribe this move to a locational reference price will remain in place for future allocation rounds (including AR6) prior to a published government decision on REMA reforms.

Engagement

To support our work on proportionate legacy protection we will involve market participants and investors to help identify and explore risks and impacts of REMA options on existing Legacy Arrangements and options for protection. Please refer to the sub-section entitled Stakeholder Engagement at the end of the Introduction to this document for additional information on our approach to engagement.

Questions:

- 27. Do you agree with our approach to assessing the impact of REMA reforms on Legacy Arrangements?
- 28. What risks do we need to consider with regard to Legacy Arrangements, and how can they best be mitigated?

Next steps

This initial assessment of options compatibility has identified a number of interactions between the remaining reform options being taken forwards. Moving beyond this test of compatibility, in the next phase of the REMA programme, as set out in the Introduction, we will need to consider the optimal balance of risk across market participants and investors, government, and consumers to achieve a least-cost system overall which delivers our power sector objectives. This overall system perspective will inform our final decisions on the optimal combination of market arrangements which are best-suited to deliver the transition to, and operation of, our future renewables-dominated power sector.

In the next stage of REMA, we will undertake a scheme-by-scheme assessment of risks associated with Legacy Arrangements and Legacy Assets taking account of feedback from our ongoing stakeholder engagement.

Consultation questions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Options compatibility and Legacy Arrangements

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

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

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

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

Appendices

Appendix 1: Challenge 1 - detailed design of Split Market and Green Power Pool

Split Market

Split Market would involve splitting the wholesale market in two, with different technologies selling into each market – all current and future generators would participate in one of these sections of the market:

- one market for all capital-intensive, non-dispatchable technologies (i.e. renewables and nuclear) with prices at long-run marginal cost (LRMC; i.e. factoring in all the costs of producing that unit of energy, including capital costs). This would essentially replace the CfD, integrating renewable investment costs into wholesale market prices;
- a residual market for flexible, dispatchable assets (e.g. gas, Power CCUS, storage, interconnection, Hydrogen to Power) with prices at short-run marginal cost (SRMC; i.e. only factoring in the cost of producing an extra unit of energy, mostly made up of fuel costs), operating according to marginal pricing analogously to present arrangements.

Suppliers/demand would be obligated to purchase power in preference from the nondispatchable market, utilising the dispatchable market residually.

While storage and interconnection would only sell into the dispatchable market, they could buy power from either market and temporally arbitrage between the markets.

Green Power Pool (GPP)

The GPP would be a centrally co-ordinated and dispatched pool for non-fuelled renewable electricity, which would operate alongside the existing wholesale market, replacing the CfD. Generation participants could include: new generation; existing generation after the end of their CfD; existing generation with a CfD to the extent that their output is not already contractually committed.

Generators would sign long-term government-backed fixed price contracts with the pool operator to sell a proportion of their output at long-run marginal cost, with prices determined at auction. From their perspective, pool contracts would function akin to a government-backed fixed-price PPA i.e. a long-term contract to supply all non-curtailed output at a price reflecting their (auction-determined) long-run marginal cost. This would effectively combine an existing CfD with an offtake PPA, i.e. the contract would continue to insulate generators from both price risk and volume risk (apart from curtailment risk).

Suppliers and large consumers would contract with the pool operator to buy agreed volumes of power at the weighted average price of the available generation in each period; receiving proportionally less power when there is insufficient generation in the pool to meet all contracted demand. These contracts would be likely to be shorter term than those for generators.

The pool operator would be responsible for resolving excess generation (i.e. selling this into the wholesale market), with the difference (positive or negative) between the long-run marginal

cost payments made to generators and the short-run marginal cost revenues from this sale shared across / recovered from all wholesale market consumers. Suppliers would, in general, be responsible for managing scarcity in the pool (i.e. insufficient GPP generation to meet GPP demand), through contracting with flexibility and/or purchasing from the wholesale market.

Appendix 2: Challenge 2 - detailed design of capacity-based CfD

Auction design

In a capacity-based CfD auction developers would bid for a capacity payment on a £/MW basis.

The auction design would need to sufficiently facilitate competitive tension between bids and technologies to ensure we can deliver the best value for the consumer.

There is a risk that a capacity-based CfD auction may overly favour low Capex projects, rather than those which offer best value to the system. Projects that are cheaper to build could bid more competitively and so be more likely to win contracts even if they are unlikely to deliver as much power, or deliver power at peak times, as comparable projects that cost more to build but might provide better value overall.

This issue may 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 able to participate in a range of markets) may anticipate higher revenues and, therefore, could 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, it may be necessary to introduce an 'availability factor' to the auction design to mitigate against the risk of favouring low Capex projects (see below for more detail). In the next phase of REMA, it will be important to understand the extent to which developers are likely to take wholesale and other revenues into account when submitting bids.

We will need to consider whether separate consideration of less mature technologies may be necessary (due to potentially higher capital costs), as has been achieved historically through the CfD pot structure.

Capacity payment calculation design

Once operational, assets will receive a regular capacity payment. This is calculated by taking generators' submitted capacity (MW) and multiplying that by the cleared payment rate at auction (£/MW).

There may also be a case to adjust the capacity payment according to an availability factor (%), a measure of the proportion of time an asset is capable of generating. This availability factor could be calculated in a range of different ways. For example, it could be set by government in advance of the auction to reflect the availability of a typical generator, according to technology type and location. Alternatively, it could be calculated for individual assets at the end of each delivery year based upon the actual availability of the asset, utilising site specific data such as weather.

An availability factor could be used to (a) mitigate against the risk of overly favouring low Capex 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, an availability factor would add complexity to the policy design, risk introducing new distortions, and reduce the level of revenue certainty for investors.

Consumer protection mechanism design

One of the main benefits of a CfD is that it gives consumers protection against high electricity prices by ensuring that generators pay back when the price of electricity goes above the strike price. We would want to maintain consumer protection through this option.

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 market reference price exceeds this maximum level. These clawbacks would happen periodically and be based on metered output.

We would need to establish the clawback arrangements in a manner which provides good consumer protection but also does not introduce new operational distortions. The cap would, therefore, likely need to be set 'low' (to provide good consumer protection, better supporting the aims of Challenge 1) and 'soft' (to avoid disincentivising or artificially deflating the value of generation at times when it is most needed).

The use of a market reference price could re-introduce some of the trading distortions and liquidity issues associated with the current CfD design. However, to mitigate this, the reference price could be formulated as per our suggestions for reference price reform in the consultation.

Gaming risk

We believe that any risk of gaming under this model would be minimal given the regular capacity payment is not dependent upon an asset's market activity. The design choices suggested above, such as an ex-post availability calculation and soft cap where generators are only paying back a proportion of their profits, would help to incentivise generators to operate in the most economical way.

Appendix 3: Challenge 3 - barriers and bespoke interventions for low carbon long-duration flexibility, and Distributed Low Carbon Flexibility

Barriers and bespoke interventions for low carbon long-duration flexibility

Table A3.1: Summary of barriers and bespoke interventions for low carbon long-duration	
flexibility	

Technology	Barriers to deployment	Proposed bespoke mechanism in the short-medium term	
Power CCUS	High Capex costs and long lead times which increase investment risk. The CM also does not address the coordination failure between Power CCUS projects and CO2 transport and storage networks. Power CCUS also encounters first mover disadvantages, as lower cost options are more likely to secure contracts.	A Dispatchable Power Agreement is being implemented for Power CCUS as it addresses the impacts of the coordination failure, cross chain risk and first mover disadvantage. The DPA proposes an Availability Payment which provides the capital return of developing and operating the capture plant. It provides a stable revenue stream to the generator reflective of plant availability. This allows the Power CCUS to participate in the wholesale energy market on a level playing field with unabated gas-fired plants. The Availability Payment is paid regardless of whether the plant is generating such that it does not incentivise displacing lower carbon/cheaper generators like nuclear/renewables in the merit order but will be incentivised to generate ahead of unabated generators that have a higher short- run marginal cost because they are faced with carbon emission costs.	
Hydrogen to Power	As outlined in our consultation on the need for a Hydrogen to Power (H2P) business model, our analysis to date indicates that the key barriers are the FOAK first-mover disadvantage, due to	As proposed in the December 2023 consultation on H2P market intervention, a hydrogen to power business model based on elements of the Dispatchable Power Agreement (DPA), designed for Power CCUS, but adapted for H2P needs is being consulted on. This	

	technology risks and higher financing costs, and reliance on nascent enabling infrastructure and future running costs. Current analysis also indicates that current market conditions do not sufficiently mitigate these barriers for all H2P plants. The current CM does not adequately cover cross- chain risks, and some H2P plants may struggle to compete against lower Capex technologies. Analysis indicates that plants with medium to high Capex plants are most unlikely to secure the clearing prices required.	could support the deployment of H2P where there is potential to do so, support the appropriate dispatch behaviour of H2P plants in the market, which offers value for money to consumers. We consider the H2P business model design as the most effective for de-risking investment in the deployment of H2P capacity and could mitigate our identified barriers to deployment.
Long Duration Electricity Storage (LDES)	A lack of revenue certainty, coupled with long-build times (for pumped hydro storage) and high construction costs were identified as key barriers to investment in the call for evidence on facilitating LDES. ¹⁰⁶ In addition, LDES also faces first mover disadvantage, as most technologies (aside from Pumped Storage Hydro) have not been demonstrated at scale.	As set out in the January 2024 consultation, a revenue cap and floor has been recommended for LDES as it addresses the impacts of high Capex, long lead times and first mover disadvantage by providing investors with minimum revenue certainty (floor) to provide debt security and a limit (cap) on revenues to avoid excessive returns.

¹⁰⁶ DESNZ, 2023, Facilitating the deployment of large-scale and long-duration electricity storage: call for evidence. Available at: <u>https://www.gov.uk/government/calls-for-evidence/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence</u>

Distributed Low Carbon Flexibility

Alongside mechanisms which provide investment support for distributed, low carbon flexibility, (for example an Optimised CM), sharper operational signals are required to reveal the full value of flexibility and increase deployment of these technologies and services.

Informed by stakeholder responses to the first consultation and ongoing stakeholder engagement, we have undertaken a review of how to sharpen operational signals for distributed low carbon flexibility. This review included:

- identifying sources of weak operational signals,
- mapping relevant work already underway across government, Ofgem and industry against the relevant signal(/s) they are expected to improve,
- identifying the relevant REMA options under consideration and mapping these against the relevant operational signal(/s) they are expected to improve, and
- an initial assessment of immediate high priority concerns for stakeholders.

The outcome of this work is summarised in the decision map in Figure A3.1, where the operational signals are shown in the pink diamonds, the work already underway in the orange squares, the relevant REMA options in the blue squares and the barriers in purple.

Operational signals

The key challenges with current operational signals that we identified through this review were:

- Inefficient market operations;
- Barriers to market access;
- Temporal signals that do not fully reflect system needs; and
- Locational signals that do not fully reflect system needs.

Work currently underway to improve operational signals

As demonstrated in the decision map (Figure A3.1), there is a significant amount of work underway across government, Ofgem and wider industry to improve these.

There are several near-term programs that sit outside of REMA (indicated in pink in the top left of the decision map), the implementation of which will be critical to enabling market reforms that can address the challenges listed above. These include retail market reform, the introduction of market-wide half-hourly settlement, the smart meter rollout, improving grid connections, network reinforcement, consumer engagement and the Smart and Secure Electricity System (SSES) reform programme, which is seeking to create a technical and regulatory framework for energy smart appliances. Furthermore, the digitalisation of the energy system is a critical enabler for distributed flexibility, as creating effective market signals will require a step change in the visibility of data and the ease and speed with which it is shared, alongside the creation of new digital tools to facilitate consumer flexibility and develop innovative products and tariffs. Other ongoing reviews include: rebalancing of policy costs, DUoS charging (being carried out by Ofgem), removing barriers for DSR in the CM, opening up wholesale market access to aggregators/load controllers through the P415 code modification, the implementation of primacy rules and ESO/NESO reforms to balancing services. All of this work will serve to sharpen operational signals provided by existing markets for distributed flexibility. These are shown in the orange squares on the decision map.

There are also several key options being considered under REMA, which are flagged on the decision map in blue and discussed in more detail throughout the main body of this consultation which, if implemented could help improve these operational signals.

Issues

Through this process, we have identified some additional market issues that are exacerbating the four barriers.

We are aware that these issues could be negatively impacting the investment cases and operational decisions of distributed flexibility assets. We will seek to address them through collaboration with industry, ESO/NESO and Ofgem to identify and inform potential solutions, as well as help expedite existing work.

These issues are shown in purple on the decision map in Figure A3.1 and detailed alongside the work currently underway to address them in the table below. It is worth noting that the work highlighted in the table is only a summary of certain key work pieces and there are many more projects underway across industry, networks operators and Ofgem which are attempting to address these issues.

Review point

As we finalise the REMA package of proposals we will review the impact of this package together with our ongoing work on price signals for distributed flexibility, to determine whether further intervention is required. Additionally, we will be able to holistically take into consideration the implications of the future market arrangements determined by the REMA programme on shaping markets to facilitate the rollout of distributed flexibility.

In the meantime, we will continue to work to address the high priority short-term issues that are outlined below in the table below and the decision map in Figure A3.1.

Table A3.2: Summary of new market issues and work currently underway for distributed	
low carbon flexibility	

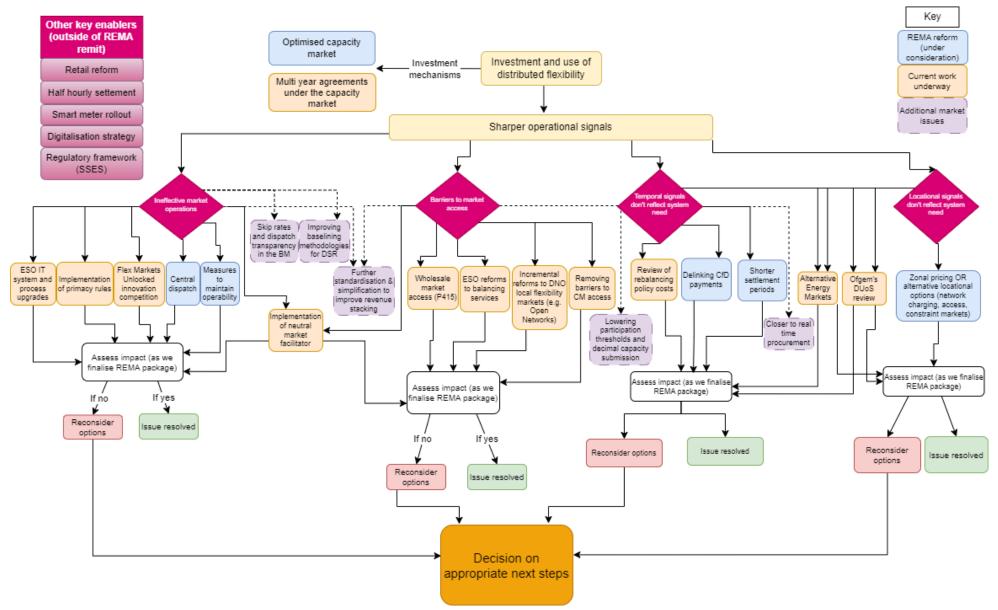
Key Barrier	Description of Problem	Work Currently Underway
Skip rates and dispatch transparency in the BM	Currently, industry are reporting high levels of distributed, low carbon flexible assets with cheaper bid/offer prices being skipped over in the merit order in favour of larger, more expensive and often more carbon intensive assets. This can occur for many reasons such as needing to meet operability requirements or IT system limitations.	The ESO/NESO is creating separate markets for ancillary services that would traditionally be procured through the BM (such as the mid-term stability market) which will reduce the rate of asset skipping to meet operability needs. The ESO/NESO is conducting control room digitalisation upgrades such as the Open Balancing Platform (release 1 launched December 2023). This will improve dispatch efficiency and enable a larger

	Additionally, current processes and IT limitations mean that storage assets are not currently able to be fully incorporated into the ESO/NESO control room's schedule plans, so cannot be utilised to their full potential.	number of small assets to be dispatched to meet a system need. The ESO/NESO is investigating reforms to improve visibility over storage asset availability that might enable them to be better accounted for in system planning and thus dispatched in greater volumes and for longer durations. The ESO/NESO has commissioned an independent piece of analysis from an external consultancy to determine a method for calculating skip rates and suggest potential improvements to dispatch transparency.
Improving baselining methodologies for DSR	Current baseline calculation methods (against which metered demand is compared to calculate the amount of DSR capacity provided) primarily use some form of historic averaging or a nominated level supplied by a provider. Moving into a future world where DSR becomes a part of everyday life these methods will no longer be fit for practice and stronger governance arrangements will be required. Additionally, having different calculation methods across different markets adds an extra layer of complexity that acts as a participation barrier for smaller providers.	Several market participants, industry groups and network operators have begun to conduct their own internal analysis and develop thought on this subject, but there is a need for more centralised coordination to ensure the right solutions are found and made consistent across markets where possible. We will work with ESO/NESO, Ofgem and wider industry to ensure this issue is given sufficient priority and that work being progressed in this space is coordinated.
Further standardisation and simplification of markets to improve revenue stacking	A lack of standardised markets and processes across markets (at transmission and distribution level) makes it harder to stack revenues, participate across markets and creates additional barriers for smaller participants.	The ENA Open Networks programme is currently seeking to, by April 2024, create a standardised prequalification process, settlement process, set of flexibility products and contracts and a dispatch API, all of which will apply across DSOs. They are also aiming to implement primacy rules and improved data sharing between ESO/NESO and DSOs.

		Through their 'future of local energy institutions and governance' reform work, Ofgem are intending to create a Market Facilitator role. The Market Facilitator will be responsible for delivering standardised, easily accessible, and transparent DSO markets, as well as for aligning ESO/NESO and DSO market arrangements. It will also have a mandate to grow and develop local flexibility markets and ensure processes are standardised to reduce friction for both large and small market participants.
Lowering participation thresholds and allowing decimal capacity submission	Currently most markets have a minimum capacity threshold which assets must meet in order to participate. These are not standardised across markets and act as a barrier to participation. Additionally, in many markets, capacity can only be supplied at integer levels of MW, so sub-MW capacity is unable to participate, and providers have to round down their capacity, undermining revenues.	The ESO's/NESO's Open Balancing Platform upgrades will mean their systems could accept sub-MW levels of granularity. Once the legacy IT systems are fully phased out (currently targeting 2027) it could be possible to lower participation thresholds and allow decimal capacity, although grid code and regulation changes will be required.
Closer to real time procurement	For most distributed flexibility assets, closer to real time markets (i.e. day-ahead and intra-day) provide the most opportunity to engage and participate.	Many services are already being procured at day-ahead stage (such as ESO's/NESO's frequency response markets), with others being considered for day-ahead procurement. Additionally, some DSOs have started to consider closer to real time procurement, including day-ahead flexibility procurement. ¹⁰⁷ More work needs to be done, however, to bring this in across networks and improve alignment in procurement timescales.

¹⁰⁷ UK Power Networks, 2024, New partnership between UK Power Networks and EPEX SPOT set to 'supercharge flexibility market'. Available at: <u>https://www.ukpowernetworks.co.uk/news/new-partnership-between-uk-power-networks-and-epex-spot-set-to-supercharge-flexibility-market</u>

Figure A3.1 – Distributed flexibility decision map



Appendix 4: Challenge 4 – operating and optimising a renewable-based system cost-effectively.

This appendix provides additional technical information on REMA Challenge 4 policy options to support stakeholders in answering the questions outlined in REMA's second consultation.

The appendix covers the following:

- Section 1 Key zonal pricing design choices
- Section 2 Further detail on Ofgem-commissioned assessment of options for potential reforms to transmission access rights
- Section 3 Detail on policy development on operability options

Section 1 – Key zonal pricing design choices

Background

Zonal pricing outcomes in GB will be contingent on policy design choices. Zonal pricing is well precedented internationally, and work within REMA to date has primarily focused on understanding these international examples and how they vary. In our next phase of work, we will be identifying which aspects of different zonal models might be best suited to a GB context if zonal pricing were to be introduced.

This appendix section outlines the key variations between different zonal models, and the key design choices we will need to consider in our next phase of work. It is not intended to be an exhaustive representation but, rather, an articulation of the choices that would most significantly influence policy outcomes. For each design choice below, we have outlined some illustrative options for each choice – these can be used to show what options might be available; however, there may be other options not listed. Crucially, no decisions have been made on the design of a GB zonal market unless stated within Challenge 4.

This appendix should also be used by stakeholders to answer Question 22:

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

In addition to key design choices, broader decisions will also be needed on what trade-offs to prioritise within a zonal market design - for example, the extent to which a zonal market design will prioritise sending operational signals versus protecting market participants from new risks, or whether to introduce more incremental or transformational changes. In the next phase of REMA, we will consider the potential costs and benefits of each of these key trade-offs.

Key design choices

Table A4.1: Number of zones/ approaches to zonal definition

Options (for illustrative purposes):			
Two zones – north/south Simplest possible organisation at expense of operational efficiency	Three to six zones Intermediate option	Seven or more zones High number of zones – high locational granularity; may require central dispatch	

Zonal pricing involves an active choice in defining the number of zones and their boundaries. More zones may mean zones better reflect transmission constraints, therefore lowering the volume (and cost) of redispatch. However, a greater number of (smaller) zones could mean that wholesale market prices in individual zones may be more volatile and less predictable.

Table A4.2: Approach to reviewing zonal boundaries

Options (for illustrative purposes):			
Reviews determined by trigger condition Boundary reviews are only conducted when a certain condition is met (e.g. congestion costs).	Lower review frequency (e.g. at least every 4 years) Zonal boundaries are less likely to represent constraints over time but may reduce potential investment uncertainty	Higher review frequency (e.g. no longer than every 3 years) Zonal boundaries will more regularly accurately represent constraints (and maximise operational efficiency) but may create more uncertainty for investors	

Zonal boundaries will likely need to be redrawn periodically to ensure that they reflect the changing constraint landscape. How often boundaries are reviewed and redrawn will affect the extent to which constraints are well-represented (and by extension dispatch efficiency) but will also affect certainty and predictability for market participants (and therefore investors).

Table A4.3: Dispatch

Options (for illustrative purposes):			
Self-dispatch Market participants can schedule and commit their output and the System Operator acts as the residual balancer, issuing dispatch instructions to ensure that supply and demand match to resolve constraints.	Central dispatch with self- commitment Both the System Operator and market participants can schedule and commit but only the System Operator can dispatch.	Central dispatch with central commitment The System Operator schedules, commits, and dispatches generation based on participants' submitted capacity and bids.	

Under zonal pricing, GB's current self-dispatch arrangements could be retained. However, zonal pricing could also be introduced alongside central dispatch (either with self-commitment or central commitment). In some cases, it may be necessary to include central dispatch. For example, a zonal market with a high number of zones may require central dispatch due to increased operational complexity. We are also considering the case for introducing central dispatch within national pricing. Please see the section on central dispatch in Challenge 4 for more detail.

Table A4.4: Demand-side exposure

Options (for illustrative purposes):					
Retain national wholesale pricing Prices for demand- side are averaged nationally	variat Avera regior differe remov retain exam	at for regional tions ¹⁰⁸ age, enduring hal price ences are ved while still ing, for ple, intra-day tional price	Average ac multiple zon Prices for de side is an av across seve zones.	n es emand- verage	No intervention Demand-side pays zonal price.
If some degree of exposure					
Opt-in mechanisms Demand-side can choo 'opt-in' to locational priv		Varied by type of consumer Certain types of consumers could receive an average national price while others pay locational prices.		granular Prices be over time	come more locational , bringing demand- alignment with

Under zonal pricing, the demand-side can face more or less locationally-reflective pricing. Increased dispatch efficiency should lead to reduced costs for all consumers and if consumers face (and change consumption patterns in response to) locationally-reflective prices, this could increase total benefits. If consumers face locationally-reflective prices, then consumers in some parts of the country could make greater savings than others (for example, consumers in the north would experience greater savings than those in the south). We will continue to carefully consider the impacts which locational pricing could have on regional differences in consumer bills. Exposure could vary between, for example, domestic consumers, nondomestic consumers, and demand side-assets (such as electricity storage and electrolysers).

Table A4.5: Support scheme design

Options (for illustrative purposes):		
Lower exposure	Greater exposure	
Assets under support schemes have limited or no exposure to locational price and / or volume risk	Support schemes have some degree of locational price and / or volume risk	

¹⁰⁸ As proposed within Policy Exchange, 2020, Powering Net Zero.

We have discussed our approach to protecting existing CfD assets under locational pricing in the Options Compatibility and Legacy Arrangements section, as well as consideration of other assets and arrangements. For new CfD contracts agreed after a decision on locational pricing there are choices on how the schemes are designed. Different options for future-proofing the CfD (as discussed in Challenge 2) may expose renewables to new locational price and volume risks introduced by locational pricing to different extents. Within some options, there are also active design choices as to the extent to which new government-supported assets are exposed or shielded to these risks, including reference price calculation, how the negative pricing rule is applied, and how auctions are designed. This is discussed further in the Options Compatibility and Legacy Arrangements section. We would also need to consider other Government Support Schemes (e.g. CM, CCUS DPA; nuclear RAB) and any necessary steps to make them compatible with zonal pricing.

Table A4.6: Market power and gaming mitigations

Options (for illustrative purposes):	
Maintain status quo (REMIT + balancing mechanism conditions) REMIT is an ex-post intervention which requires market participants to provide details of inside information/ insider trading and for firms administering transaction to report 'suspicious transactions to Ofgem'. Ofgem and ESO have also implemented and are considering several interventions to address gaming in the GB Balancing Mechanism.	Introduce additional mechanisms These could include the use of long-term capacity contracts for balancing.

Under zonal pricing, we will need to consider how to monitor and mitigate market gaming opportunities which exist in zonal markets. Market gaming opportunities exist in zonal markets due to the redispatch stage, with the primary gaming strategy known as 'increase-decrease gaming' – where market participants adjust their behaviour in the day-ahead market to profit excessively at the redispatch stage. This behaviour already exists in the current GB Balancing Market. We would therefore need to consider whether existing mechanisms, such as REMIT, in isolation would be sufficient mitigation or whether additional mechanisms would be appropriate; for example, procuring long-term capacity contracts for balancing.

Options (for illustrative purposes):				
Financial Transmission Rights (FTR) options Holders receive financial compensation equal to the price difference between two zones.	Financial Transmission Rights obligations The same as FTR options, but holders must pay back if difference is negative.	Energy Price Area Differentials A type of financial derivative on the difference between zonal price and system price.	Physical Transmission Rights (PTR) Provide the option to transport a certain volume of electricity in a certain period of time between two areas in a specific direction. PTRs would likely be allocated by the System Operator.	

Zonal pricing will introduce new risks for market participants, including locational volume risk due to the removal of guaranteed firm access rights across zones under zonal pricing, see the Options Compatibility and Legacy Arrangements section for more detail on locational volume risk. To mitigate this risk, we will need to consider whether to introduce additional hedging products for market participants. These hedging products are well precedented internationally, but further work is needed to understand how these options would apply in a GB context.

Table A4.8: Approach to interzonal capacity allocation

Options (for illustrative purposes):		
Explicit allocation	Implicit allocation	
Inter-zonal capacity allocated separately to the trade of electricity.	Inter-zonal capacity allocated together with the trade of electricity.	

Zonal pricing would mean dividing GB into separate zones, each with their own market. The establishment of these different markets means we will need to consider how to allocate interzonal capacity for market participants to buy and sell power across zones. There are two possible approaches to allocating inter-zonal capacity: explicit and implicit allocation. Under explicit allocation, market participants would buy/sell power and book capacity on interzonal interconnectors separately. Under implicit allocation, bids and offers for cross-zonal trade would be cleared and settled centrally considering available cross-zonal capacity. It is possible that both implicit allocation in forward markets and implicit allocation at day-ahead stage. In the next phase of work on designing a zonal market, we will need to carefully consider what this and other zonal design choices could mean for the role of OTC markets, brokers, and power exchanges across different trading timescales.

Other considerations

As noted above, this list is not exhaustive and there are a wide range of design implications which we will need to consider if a zonal pricing model is introduced beyond those discussed here, including the approach to network charging, approach to representing transmission capacity and Balancing Mechanism design. Further consideration of the treatment of existing generation and flexibility assets, as well as cross-border energy trading, is discussed in Challenge 4.

Section 2 - Further detail on Ofgem-commissioned assessment of options for potential reforms to transmission access rights

Ofgem are considering options for reforming transmission access rights to send more effective locational signals. To do this, earlier this year Ofgem and DESNZ commissioned external consultants to undertake targeted analysis to consider options for reforming transmission access rights to send more effective locational signals. This work was an initial assessment, as part of early policy scoping work, and further work will be undertaken in the next phase of policy development to consider the interaction of access reform options with broader changes to the wholesale and balancing market arrangements, dispatch arrangements and investment support schemes. The purpose of this appendix section is to provide more detail on the individual options Ofgem are considering and the high-level assessment of each of the options.

A short-list of four options was considered in the initial assessment, with the options aiming to better reflect the scarce nature of network capacity and to minimise overall costs. The options considered either changing access for new users only or for existing and new users. These options are presented below at a high-level; they contain ranges of optionality within themselves, such as whether they would be enduring or transitional based on the progress on network build, and whether they would be static or dynamic (e.g. temporal or locational). As noted in Challenge 4, of the options detailed below, options 3 and 4, which would involve changing access rights for existing assets, **would only be considered if introduced alongside more major REMA reforms,** specifically zonal pricing or central dispatch.

Background on options

Options 1 and 2 involve only making changes to access rights for new assets, which would limit system benefits but could be less disruptive, while options 3 and 4 would change access rights for all users, thereby representing a significant market design change. This work did not quantify the potential benefits associated with these design options or consider how the options would work alongside other options sending similar signals, such as transmission network charging, design of government investment schemes and/or greater coordination of infrastructure build and changes to balancing services markets. The options examined were:

 Administrative allocation of firm access for new users: Existing users retain current financially firm access, maintaining the right to compensation when constrained up or down. New users would have the option of receiving reduced access rights in return for faster connection to the network and/or a lower price of connection. This could be time-limited and network-dependent, or on an enduring basis. Any firm access right to new users would be allocated based on an administrative mechanism. Non-firm access generation would be constrained first; and if needed, the ESO would then constrain firm users using offers/bids into BM. The appropriate design of connections arrangements is also being considered as part of our wider work on connections reform in the context of our Connections Action Plan.¹⁰⁹

- 2. Auctions for firm access rights for new users: Existing users retain current firm access, maintaining the right to compensation when constrained up or down. Firm access rights are auctioned for all new users (for example, all connection applications received in the same year could be eligible to participate in an auction for firm access rights). New users would have the option of receiving reduced access rights in return for a quicker connection and/or a lower price of connection and the ESO would first constrain non-firm users before constraining firm users using offers/bids into BM.
- 3. Local firm access rights only: Access to the entire network is removed, with new and existing users only having firm access to their 'local' network.¹¹⁰ This is similar to potential options for access rights in zonal pricing (e.g. no firm access beyond connected zone) but if implemented without zonal price signals to facilitate optimised scheduling it could lead to a less efficient dispatch compared to current arrangements, as the ESO would have to manage constraints between the defined local areas by constraining users on a non-economically optimal basis (e.g. last in, first off). For this option to be viable, it would require some form of a zonal pricing market.
- 4. Removal of financial access rights to entire network for all users (including existing): Users only have firm access to their immediate node. The ESO would be able to constrain all users on an administrative (e.g. a non-price) basis in order to operate the system reliability. In this option, users would not receive any financial compensation for being constrained off. Under this option, there would need to be some way to economically optimise a dispatch arrangement, which could not be done without a single operator having visibility of all market participants' marginal bids. This could mean that removal of firm access for all network users could require the introduction of central dispatch to maintain an economically efficient and feasible system operation.

All options provide scope for access rights to send locational investment signals, specifically to discourage investment of generation in export constrained regions and demand in importconstrained regions. There is a risk, however, that without further reforms alongside these changes, reforming access rights could have a negative impact on levels of investment needed to reach our net zero targets.

These options should also be considered alongside other potential reforms to ensure they send effective operational signals, or at least improve cost-effectiveness of the system operation. Under current arrangements, the ESO changes unit-dispatch in operational timescales through the BM, which provides a cost-reflective bid/offer stack to inform re-dispatch. Introducing non-firm access for new users only (Options 1 and 2) would create a two-tiered re-dispatch system, with non-firm users constrained first, regardless of the cost and carbon implications for wholesale scheduling and dispatch. This could disrupt the merit order (e.g. plant that should have been in the merit order is constrained-off), and as a result more expensive and higher carbon plant would set the market price for all, which could increase the clearing price relative to current arrangements.

As options 3 and 4 change access rights for all users, they would avoid the introduction of a two-tiered dispatch and potential disruption to the merit order and associated costs. However,

¹⁰⁹ DESNZ & Ofgem, 2023, Electricity networks: connections action plan. Available at: <u>https://www.gov.uk/government/publications/electricity-networks-connections-action-plan</u> ¹¹⁰ Decisions would need to be taken on the definition of 'local'.

they would require much greater levels of reform to be efficient, such as implementing locational pricing or a centralised dispatch arrangement. They would also likely require some sort of compensation for existing users, which would reduce the consumer benefits of such action. International evidence suggests that a lack of financially firm access rights combined with national pricing could lead to widespread distortive behaviour in the wholesale market, especially from low or even negative bidding from renewables clustered behind a constraint. As above, these options will only be considered further alongside more major REMA reforms.

For all options, there may be ways to mitigate potential negative investment implications or operational disruption that could ultimately result in an overall more cost-effective, secure market compared to current market arrangements. Further work is required in this space as we currently do not have full visibility of the practicality of these reforms, their likely effectiveness, or further potential unintended consequences associated with such an approach. This further work and assessment will take place in the next phase of REMA.

Section 3 - Detail on policy development on operability options

The table below shows how the policy options on operability that we consulted upon in Chapter 9 of the first REMA consultation (2022) have evolved and been refined into the proposals that we have presented in this consultation. We indicate where policy options have been introduced since the consultation and where they will be covered elsewhere in the consultation. Note that options 2 to 5 relate to the option 'Enhanced existing policies' in Chapter 9 of the 2022 consultation.

2022 consultation proposal (previous)	2023 consultation proposals (new)	Rationale for revised position
1. Continuing with status quo	Existing policies should be strengthened.	Existing policies to address the challenge to operability that we identified in REMA's case for change are delivering improvement but there is scope to build upon them to help ensure that we meet the challenge to ensure secure and cost-effective system operability as we make the transition to net zero.
2. Giving the ESO or National Energy System Operator (NESO) the ability (or an obligation) to prioritise zero/low carbon procurement.	A set of measures to provide confidence that ESO/NESO will develop a path to a fully decarbonised electricity system subject to security of supply by 2035 ('a' to 'c' below):	These measures would deliver a stronger signal that a fully decarbonised electricity system, subject to energy security, can be credibly delivered by 2035. We consider that prioritisation of low carbon procurement by the ESO/NESO, as per the option in the 2022 consultation, could be excessively complex to exercise and

Table A4.9: evolution of options on electricity system operability since the first REMAconsultation

		might inhibit the ability of ESO to operate the system efficiently.
	a) An electricity system operability strategy for 2035, to be published by ESO.	This will give the market greater clarity on how system operability can be maintained in a way that is consistent with the government's 2035 decarbonisation commitment, at least cost. This would build on ESO's existing aim to be capable of operating the system at net zero from 2025 for at least one settlement period.
	b) ESO to improve forecasting of medium to long-term operability needs, including by location where relevant.	A firmer picture of future system operability needs will allow market participants to make investment decisions for enabling low carbon ancillary services with greater confidence. This will also complement the proposal for an operability strategy (above).
	c) Improved greenhouse gas (GHG) emissions reporting on ESO/NESO operability activity across all electricity markets.	More granular carbon emissions reporting of ESO's operability activity would provide a useful tracking function of their progress in meeting the 2035 decarbonisation commitment. This could potentially include data on both carbon intensity and tonnes of carbon emitted by action type; for example, for constraints management, reserve, and inertia.
3. Ensuring the ESO/NESO strikes the optimal balance between long and short-term contracts for ancillary services.	Greater transparency on ESO policy for procurement.	ESO have published a set of principles for determining contract length in their Market Roadmap document. ¹¹¹ It will continue to adhere to these principles it is procurement policy. We consider policy for addressing 'skip rates' in Appendix 3.
4. Alignment of long- term ancillary services contracts	To continue to explore how long-term ancillary contracts and CfD and CM tendering could be	In assessing this option, practical difficulties have emerged in identifying how alignment could be achieved. For example, co-clearance of

¹¹¹ ESO, 2023, Markets Roadmap 2023. Available at: <u>www.nationalgrideso.com/research-and-publications/markets-roadmap.</u>

with CfD and CM tendering.	coordinated to allow investors and developers to make business investments decisions with a greater level of certainty.	tenders/contracts is likely to be infeasible due to the level of complexity it would involve. However, for a limited number of 'longer term' contracts which are awarded further ahead of delivery, there could be scope to move closer to timing of CM and CfD auctions. We are exploring with ESO and other stakeholders the scope for better alignment.
5. Matrix procurement of ancillary services	ESO to proceed with Enduring Auction Capability Auction	ESO's Enduring Auction Capability (EAC), which will enable a substantial degree of co-optimisation within ancillary services, will to a large extent effectively provide the benefits of this option. It will allow assets to offer to the EAC multiple frequency response and reserve ancillary services; a market clearing algorithm then allocates each unit to the 'optimal' service. There could be scope for the EAC to be scalable and extendable to any future services and products.
6. An expanded role in the operability of networks at a local level, which could include procurement of ancillary services from local markets.	Work already underway	In the first consultation we sought views on a greater role for DNOs in managing operability, as well as on the extent that existing and planned coordination activity between ESOs and DNOs ensures optimal operability. Ofgem have since carried out a review into local governance arrangements and in November 2023 recommended the introduction of regional energy strategic planner and assigning a market facilitation function to a single entity to deliver more accessible, transparent, and coordinated flexibility markets. ¹¹² In addition, the work under the Energy Network Association's (ENA) Open Networks project continues to be critical to improve DNO/ESO coordination and facilitate open and accessible markets to unlock the full value of flexibility being offered. We will progress this through our ongoing work overseeing the

¹¹² Ofgem, 2023, Decision on future of local energy institutions and governance. Available at: <u>www.ofgem.gov.uk/publications/decision-future-local-energy-institutions-and-governance</u>

		implementation of actions in the 2021 Smart Systems and Flexibility Plan in order to improve coordination across the national and local levels, creating a clearer route to market, increasing investor confidence, and promoting whole-system flexibility.
7. Modification of the CfD to remove disincentives for assets that are supported by the scheme to engage in ancillary services markets.	We will consider the scope for incentivising the provision of ancillary services in assessing options for reforming the financing of renewable generation, such as deemed generation.	In Challenge 2 we set out our thinking the reform of the CfD. This includes options that would break the link between metered generation and subsidy payment. Doing so should help lower participation barriers to ancillary service markets for CfD-backed assets. Additionally, the government has recently consulted on potential CfD reforms for AR7 (scheduled to open in 2025) and beyond, including introducing new hybrid metering arrangements for CfD generation co- located with other assets, which could support increased provision of flexibility and ancillary services.
8. Co-located assets and barriers to provision of ancillary services	Exploring perceived barriers to the provision of ancillary services from co-located assets (this option was not included in the first consultation).	Stakeholders raised specific concerns about perceived barriers to the provision of ancillary services from co- located assets (such as storage, generation, and electrolysis) due to factors including metering arrangements and the asset ownership rules under the Offshore Transmission Owners (OFTO) regime. We will continue to investigate the extent to which these constitute barriers. Progress has already been made in clarification of metering arrangements by updated guidance issued by the Low Carbon Contracts Company. ¹¹³

¹¹³ Low Carbon Contracts Company, 2023, CfD Co-location Generator Guidance. Available at: <u>https://www.lowcarboncontracts.uk/resources/guidance-and-publications/cfd-co-location-generator-guidance/.</u>

9. Modification of the Capacity Market so that it requires or incentivises the provision of ancillary services.	We are retaining the Capacity Market as the future capacity adequacy mechanism and optimising it to better align it with our net-zero emissions target by introducing multiple clearing prices in the auction in the form of low carbon flexibility minima. Further work is underway to develop how minima should be defined and set (for example, low carbon, response time, sustained response); as such we will continue exploring this option as part of the Optimised CM work.	In Challenge 3, we set out our thinking on reform to the Capacity Market. There are no barriers to the participation of assets in both the Capacity Market and Ancillary Service markets.
10. Co-optimisation of ancillary services	We will continue to consider the case for co- optimisation as part of the option for centralised dispatch.	We are awaiting research commissioned by ESO before assessing whether there is a case for moving away from the current self- dispatch arrangements. This research will assess how effectively the current dispatch arrangements are working, and the possible benefits of 'co- optimisation' under centralised dispatch.

Appendix 5: Legal Duties

Public Sector Equality Duty (PSED)

Government has undertaken analysis as part of the public sector equality duty (PSED) process and we do not consider it to raise any issues that require adaptations to the remaining options under REMA at this stage. We will continue to assess the equality implications of these options and will keep the PSED closely under review.

Of REMA's remaining policy options, two options have been identified as having the potential to directly and disproportionally impact consumers with protected characteristics under the Equality Act 2010: the introduction of locational pricing and the review of transmission network charging. Policy development is still underway and options to protect consumers, in the event these policies are taken forward, remain under consideration. Government has reviewed research and undertaken comprehensive stakeholder engagement to better understand impacts on consumers generally, including groups with protected characteristics. To date, this has included a series of End User Forums and End User Challenge Panels jointly run with Citizens Advice and Sustainability First.

The nature of protected characteristics means that any disproportionate impact on consumer bill increases may be compounded for individuals who are represented across more than one of the protected groups. We will continue to consider this when developing policy decisions. As well as possible options for shielding consumers as part of REMA, there may also be the opportunity to shield consumers downstream through retail market policies and interventions. Equality considerations are considered in tandem with decision-making and will be subject to review as the REMA programme matures, prior to the end of policy development and before any decisions on spending are made.

Environmental Principles Policy Statement (EPPS)

The Environment Act 2021 sets out a legal duty for government ministers to have due regard for the Environmental Principles Policy Statement (EPPS) when making policy. This duty came into effect on 1 November 2023.

Reform of the electricity markets will affect DESNZ's efforts to ensure the UK meets its net zero commitments to reduce its greenhouse gas emissions. Accordingly, DESNZ officials have been considering the likely environmental impact in the development of the policy options outlined in this paper. Our initial analysis indicates that a more efficient electricity system would potentially result in operational improvements meaning thermal plants run less often, resulting in a positive environmental impact. The final impact on how thermal assets would run can only be assessed once more detailed proposals are developed in the next stage. However, this is coupled with a potential negative impact in the short-term relating to the use of unabated gas whilst renewables capacity is increased.

Following this consultation process, we will continue to consider the environmental impact. Ultimately, any policy decisions on REMA will be made with due regard for the principles outlined in the EPPS.

Glossary

	Now annual auctions for Contracts for Differences (CfDs), which see projects from a range of different renewable technologies competing to secure CfD support.
	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).
	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.
Storage (BECCS)	Bioenergy with Carbon Capture and Storage is a class of technologies which combine the use of biomass to produce energy or fuel with carbon capture and storage technologies.
	Specific policy support to bring forward investment for low carbon flex, which due to technology specific risks is unable to compete in the current Capacity Market (CM).
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 ESO.
,	Electricity generated from fossil fuels is taxed to guarantee a minimum price for CO ₂ emissions.
	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 called on by the Electricity System Operator 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.
Sixth Carbon Budget (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.
Combined-Cycle Gas Turbine (CCGT)	An electricity generation technology in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency.
Carbon Capture, Usage and Storage (CCUS)	A technology for capturing carbon dioxide (CO ₂) that would otherwise be emitted from a process (e.g. electricity generation) and either using it (often in industrial processes) or permanently storing it.
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.
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.
Consumers	Those that consume electricity. There are two broad categories of consumer, domestic consumers (e.g. households) and non-domestic

consumers. A non-domestic consumer is one that is not a domestic customer, such as a business or an industrial user, which could have a variety of energy related needs.
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.
A financial market where market participants purchase and sell electric energy at financially binding day-ahead prices for the following day.
An option in the consultation that removes the link between an asset's metered generation and payment/clawback amounts in the CfD scheme, by using a combination of asset-specific data to estimate what individual asset's generation output should have been at any given point.
In the context of this consultation, demand reduction refers to the permanent reduction of electricity demand delivered through installation of electrical energy efficiency measure; 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.
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 plants can break down from time to time, and wind and solar output varies day to day.
Dispatchable generation refers to sources of electricity that can be produced on demand, according to market need.
Distribution Network Operators are the regulated companies that own and operate 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.

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.
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.
Electricity Market Reform (EMR)	A set of reforms (including the CfD and Capacity Market) introduced by the government in 2013 to incentivise investment in secure, low carbon electricity.
Emissions performance standard (EPS)	A standard which limits CO ₂ 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.
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. See also: NESO.
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

First-of-a-Kind technologies (FOAK) Frequency response	demand, integrating renewables, and maintaining the stability of the system. Flexibility technologies include electricity storage, flexible demand, CCUS, hydrogen power, and interconnectors. Examples include certain kinds of battery storage technologies. ESO have an obligation to control system frequency at 50Hz plus or minus 1%. To help do so they procure several different types of frequency response services from electricity assets.
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 policy option - 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.
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.
Inertia	Inertia refers to kinetic energy 'stored' in the electricity system that acts as a cushion against sudden changes in frequency that is caused by faults or changes in demand and supply. Inertia has historically been provided by coal and gas- fired generators, as they contain large synchronous rotating masses. As we move towards a fully decarbonised electricity system inertia will increasingly need to be managed through new low carbon technologies.
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 CfD contract. 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.
Low Carbon Contracts Company (LCCC)	A government-owned company that is operationally independent and manages the CfD scheme at arm's length from government.
Long Duration Electricity Storage (LDES)	Encompasses a group of conventional and novel technologies, storing and releasing energy through mechanical, thermal, electrochemical, and chemical means. LDES will be pivotal in delivering a smart and flexible

	energy system that can integrate high volumes of low carbon power, heat, and transport.
Legacy asset	An asset used in the generation, transmission, distribution or supply of electricity which is the subject of a Legacy Arrangement.
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.
Locational signals	Pricing signals for generating assets which would incentivise or disincentivise generators to change electricity output to the grid based on changing electricity demand in a particular location.
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.
	In addition, please refer to nodal pricing and zonal pricing definitions.
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.
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.
Low carbon minima	An Auction Minima specific to a low carbon group of technologies. Also see minima.
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 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.
Network constraint costs	The 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.
Net Zero Strategy	This strategy, published in October 2021 by the UK Government, sets out policies and proposals for decarbonising all sectors of the UK economy to meet our net zero target by 2050.
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 (OTNR)	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 (Power CCUS)	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 large 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.
Review of Electricity Market Arrangements (REMA)	Please refer to the executive summary and introductory section for an overview of REMA.
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.
	This scheme provides certificates called REGOs which demonstrate electricity has been generated from renewable sources.
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.
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.
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.
Strike Price	The price determined to be paid to an electricity generator per MWh of production in an auction under the CfD.
System Stress Event	Occurs when demand for electricity outstrips supply; it is defined in Rule 8.4.1 of the Capacity Market Rules.
Targeted Tender	An option considered as add on to the CM where tenders are issued for new build capacity with specific requirements for construction i.e. technology type or location.
Temporal signals	Temporal signals, sit alongside operational signals, may encourage network users (generation, demand or storage/flexibility providers) to flex demand or supply of electricity at a certain time.
Trade and Cooperation Agreement (TCA)	Trade and Cooperation Agreement between the UK and the EU.
Transmission Network Use of System Charges (TNUoS)	Charges which recover the costs of installing and maintaining the transmission system in England, Wales, Scotland, and offshore.

Unabated assets	A fossil fuel plant that has not installed technology that reduces its carbon dioxide emissions.
Value of Lost Load (VoLL)	This is a monetary value expressing the costs associated with an interruption of electricity supply.
Winter margin	In winter, electricity demand can be at its highest, and due to weather patterns, renewable production can be reduced. The 'margin' is the difference between supply and demand for electricity at any given time.
Zonal pricing	Under zonal pricing, the network is split into clearly defined zones. The boundaries of the zones are drawn to reflect where major transmission network constraints occur. In a zonal market, each individual zone has a single price which assumes no network constraints within the zone. Please also refer to the definition for locational pricing.

This consultation is available from: www.gov.uk/government/consultations/review-of-electricity-market-arrangements-rema-second-consultation

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