CORNWALL INSIGHT

CREATING CLARITY

Insight paper

REMA: Reform to support Mass Low Carbon Power

RenewableUK, Solar Energy UK & Scottish Renewables

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2. Executive summary and key findings

This report explores the potential of delivering transformational change to the GB energy system as outlined in the Review of Electricity Markets Arrangements (REMA) consultation via evolutionary reform through options from the mass low carbon chapter of the REMA consultation. Options being considered under REMA offer the opportunity for incremental reform that will deliver the overall goals of the energy transition. More revolutionary options under consideration could bring about costly disruption for those in the energy market and deter essential investment, or risk the timely delivery of net zero.

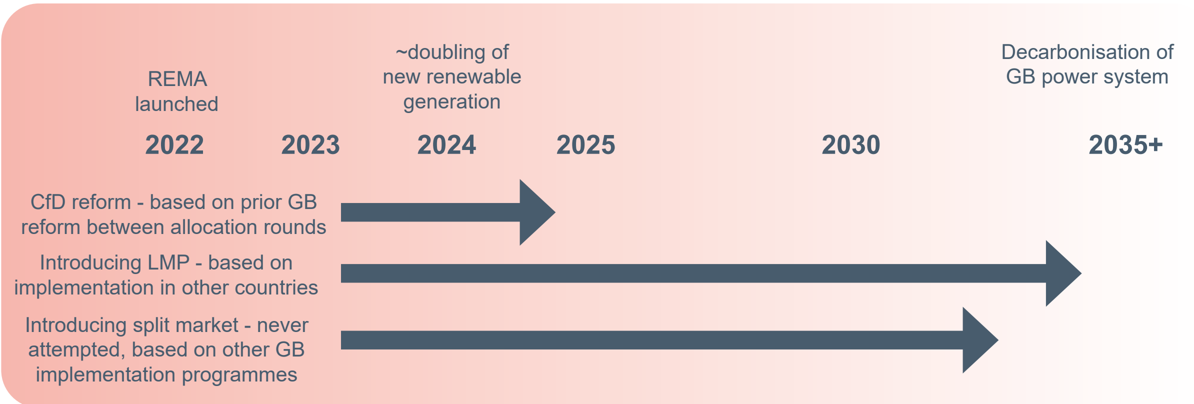
The Department of Energy Security and Net Zero ("DESNZ") is undertaking a substantial review of the electricity market to ensure the system is fit for future purpose – most recently detailed in the *Powering Up Britain* blueprint in March 2023. The UK has legally committed to achieving net zero emissions by 2050, and set a target to decarbonise the energy system by 2035. While significant decarbonisation progress has been made already, there is broad agreement that market arrangements must adapt to achieve net zero in the required timelines, while also ensuring affordability for consumers and security of supply. Safeguarding the operability of the energy system during the decarbonisation of the economy will require careful consideration about the impact of complex policy combinations. Achieving net zero emissions within the required timelines demands urgent transformative action.

An initial consultation on the options under REMA opened in July 2022, outlining the case for reform and proposing options that might be considered. The options explored in the REMA consultation included evolving existing programmes, as well as more radical reform. As would be expected for a reform programme of this scale, responses to the REMA consultation came from a broad range of market participants across the value chain, including investors, generators, suppliers, central bodies and academics. **Respondents "strongly supported" continuing to consider incremental changes to wholesale market arrangements and opinions were "divided" on more transformative changes.** Many respondents supported exploring adjustments to the existing market arrangements and reforming existing, familiar processes to achieve the required system transformation. Sentiments on more revolutionary changes – such as introducing Locational Marginal Pricing (LMP) - were mixed.

DESNZ acknowledges the goals of REMA and net zero more broadly will be achieved by ensuring "**continued investor confidence in our energy system and assets**". Revolutionary change such as LMP introduces greater uncertainty for investors, starting during the design phase. The long lead time required to plan revolutionary changes, and engage with critical stakeholders, could result in an investment hiatus that becomes normalised. Market competition could be reduced as plans for generation, network investment or storage are paused pending certainty about return on investment. Investors with mobile capital are likely to see investment in other territories with more definite policy positions as more attractive.

As currently scoped, REMA would result in significant changes to the GB energy sector which would require a major reform programme to deliver. Support for reform is accompanied by an acknowledgement that such change will take time and cause negative disruption during the transition period. Using previous programmes of change as examples, **some incremental changes could be operational within 18 months. More radical reforms like LMP might take too long to implement to play a part in decarbonising the power sector by 2035**. Operational delays may prolong uncertainty, or delay decarbonisation benefits being realised, putting net zero decarbonisation objectives at risk.

Figure 1: Projected timelines for delivery based upon prior programmes of reform



Source: Cornwall Insight

This report considers how evolutionary reforms could achieve REMAs aims without the significant risks that come with the more revolutionary options. In partnership with other options in REMA, the options for CfD reform include:

- Longer average reference price period
- Strike price range
- Deemed output
- Revenue cap and floor
- Longer agreement durations
- Locational CfD

These options were chosen for study in this report given their prominence in industry discussions, and to explore the strong potential held in evolutionary reform if granted suitable policy focus and smart market design. Reform of the CfD would be combined with other complementary reforms to drive the desired evolution and transformation of the energy system.

Two options were expanded to illustrate the effectiveness of incremental reform accompanied by strong policy direction.

- **A CfD based on deemed generation** – electricity generation plants are paid based on their potential to generate in a particular period, rather than their actual generation behaviour

- **A revenue cap and floor** – electricity generators would compete in the full range of markets (capacity, wholesale, balancing, ancillary services), and if they do not meet a minimum revenue amount, then they would be topped up at the end of the period

REMA Assessment Criteria	Description	Deemed output CfD compatibility	Revenue cap and floor CfD compatibility
Least cost	Market design solutions should offer best value for the consumer and reflect long term whole system costs and benefits		
Deliverability	Changes must be feasible within specified timescales and aim to cause the least amount of disruption possible throughout the transition, taking into account the highly complex and integrated nature of the power system.		
Investor confidence	Investor confidence needs to be maintained and built, and investment risks should be borne by those best able to manage it.		
Whole system flexibility	Where it is efficient to do so, market design should encourage market participants to act flexibly.		
Adaptability	Market design should be adaptive, responsive to change, resilient to uncertainty, such as where commodity prices fluctuate or new system requirements emerge.		

Whereas the current CfD incentivises generators to run whenever possible, under the deemed output approach exporting energy would not be needed in order to guarantee payments. Instead, generators would be able to participate in other markets, such as the Balancing Mechanism, knowing that any potential top-ups would be unaffected. This would provide a number of benefits from a system operation point of view, as payments to turn down CfD generation would no longer need to exceed the value of the subsidy payments. Generators would also be able to innovate to provide other services. Additional complexity from introducing a deemed element to the CfD scheme would be offset by longer term certainty for investors, and the overall familiarity with the core scheme. If this approach gains industry consensus, the deemed output approach has the potential to bring significant benefits.

Like the deemed output approach, the revenue cap and floor helps to incentivise generators to participate in other markets and demonstrate flexible behaviour, rather than just maximising output. With the potential for greater revenues to be achieved by participating in multiple markets, generators would instead be able to vary their activities and offer a wider variety of services in order to go beyond the floor level. As with the deemed CfD approach, this also gives rise to system operation benefits, due to an increased willingness to turn down.

Both the deemed output CfD and revenue cap and floor would incentivise more flexible behaviour from generators, helping to address the major issue of output being maximised where this is not beneficial to the system. Both options have the potential to improve on the proven CfD, scoring well across a range of key measures set out in REMA, supporting achieving net zero by 2035.

The deemed output and cap and floor options could remove the potentially unhelpful incentive for CfD generators to maximise output at all times and encourage behaviour that is more beneficial to the system without impacting on revenues and investor confidence. The options demonstrate the potential to support the Government's overall policy goals as set out in REMA. These reforms to the CfD could be combined with additional incremental reforms to market arrangements to produce an evolutionary package capable to deliver the REMA objectives more quickly and with less risk to investment. Based on analysis of prior programmes of GB and global energy market reform, more revolutionary changes can be time consuming. For example, **estimates about the length of time it would take to implement LMP illustrate the risk of being too late to positively impact the Government's time-bound net zero goals**.

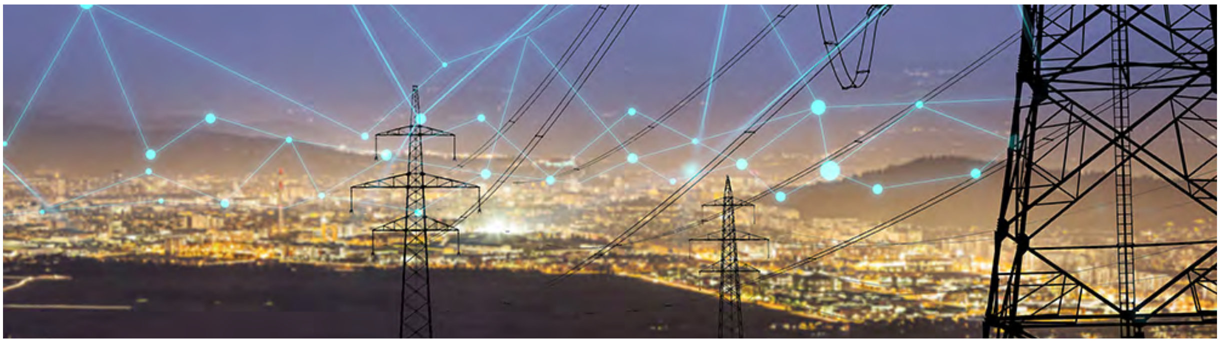
Creating a solid and future-proof market design that creates suitable investment signals is paramount, and speed is of the essence. There is a real possibility of an investment hiatus if market design uncertainty persists, with generators taking action to avoid the risk of committing capital to what will become stranded assets. Priority should be given to creating a market that incentivises action and building work delivered in time to contribute to meeting net zero targets.

Establishing policy certainty is paramount to avoid a GB investment hiatus, losing years of building opportunity and weakening supply chains in an increasingly competitive global environment.

Revolutionary reform options, such as LMP, should not progress without improved evidence they would likely deliver the preferred objectives – e.g. that it can incentivise siting decisions in a way that lowers congestion, that it would not impede the 2035 and the 2050 net zero objectives because of long project delivery times, and that the increased cost of capital due to investor uncertainty would not outweigh any other potential benefits.

The upcoming Autumn 2023 REMA consultation from DESNZ presents an ideal opportunity to test a baseline cost/benefit analysis of options for reform with market assumptions. Suggestions for questions for stakeholders can be found in section 6.3.

Cornwall Insight is an independent energy consultant with extensive experience in market and policy analysis. This report was produced by Cornwall Insight on behalf of RenewableUK, Solar Energy UK and Scottish Renewables.



3. Future market design challenges

Since 2021, the wholesale energy market has seen extensive volatility and record-setting prices driven primarily by developments surrounding the war in Ukraine. Cornwall Insight forecasts power market volatility continuing throughout the decade.

In 2023 the global energy market is very different to when privatisation occurred in GB in the 1990s, or even compared to the energy market reforms of the 2000s. The net zero transformation is underway, exposing the limitations of existing market design.

Cross cutting national matters will require decisive policy decisions and clear departmental ownership. Long term reform is recognised as the best way to protect consumers of the future, designing better markets and reducing reliance on costly, reactive policy measures. There's limited capacity for primary legislation each parliamentary session. Looking ahead, the legislative timetable and DESNZ's resources could be strained by politically urgent matters such as bill affordability for homes and businesses, or transitioning heat away from gas, or energy efficiency.

Acceleration of low carbon investment in GB - The target to achieve net zero greenhouse gas emissions by 2050 was enshrined in legislation in 2019, with a non-legally binding UK Government goal for the electricity grid to be fully decarbonised by 2035.

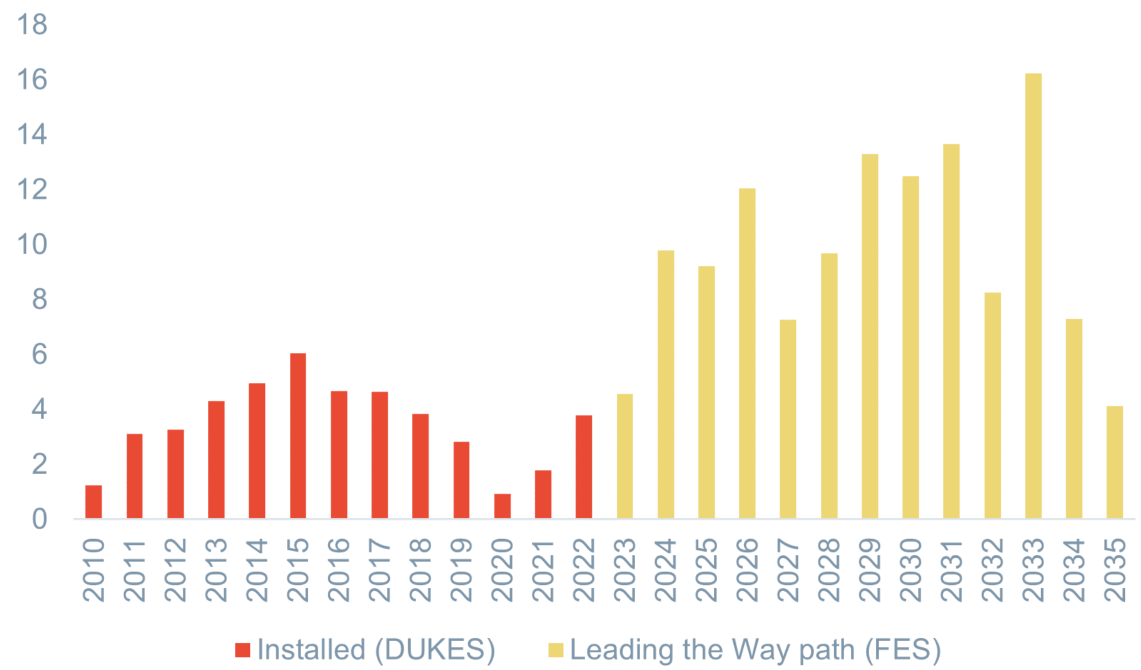
A range of policies and strategies have been put forward in support of these decarbonisation ambitions. Offshore wind deployment ambitions aim to increase capacity from 11GW to a targeted 50GW by 2030, including 5GW of floating offshore wind, an increase from the previous 40GW and 1GW. Onshore capacity will increase beyond 14GW with a Scottish government ambition of an additional 12GW by 2030, alongside development in Wales and the potential for a lifting of the de-facto ban in England. Up to 70GW of solar power capacity is targeted by 2035, up from 14GW.

On the current trajectory DESNZ expects that by 2027 existing or new support schemes will lock in around a third of installed capacity needed to meet 2035 energy demand. The BEIS Higher Demand Scenario forecast 300GW of capacity could be needed by 2035, up from around 100GW today. The National Grid Energy System Operator (the ESO) uses its Future Energy Scenarios (FES) to represent a range of different, credible ways to decarbonise the GB energy system. The FES Leading the

Way (LtW) pathway would see net zero reached in 2047. 2016 saw record renewable generation capacity installed – 6 GW. The Leading the Way pathway sees this volume being exceeded annually from next year (2024), illustrating the challenge of scaling up generation development.

To identify market reforms to support the transition to a decarbonised, cost effective and secure electricity system, the Government launched the Review of Electricity Market Arrangements (REMA).

Figure 2: Renewable generation capacity deployed per year, actual 2010-22, required under FES LtW 2023-35 (GW)



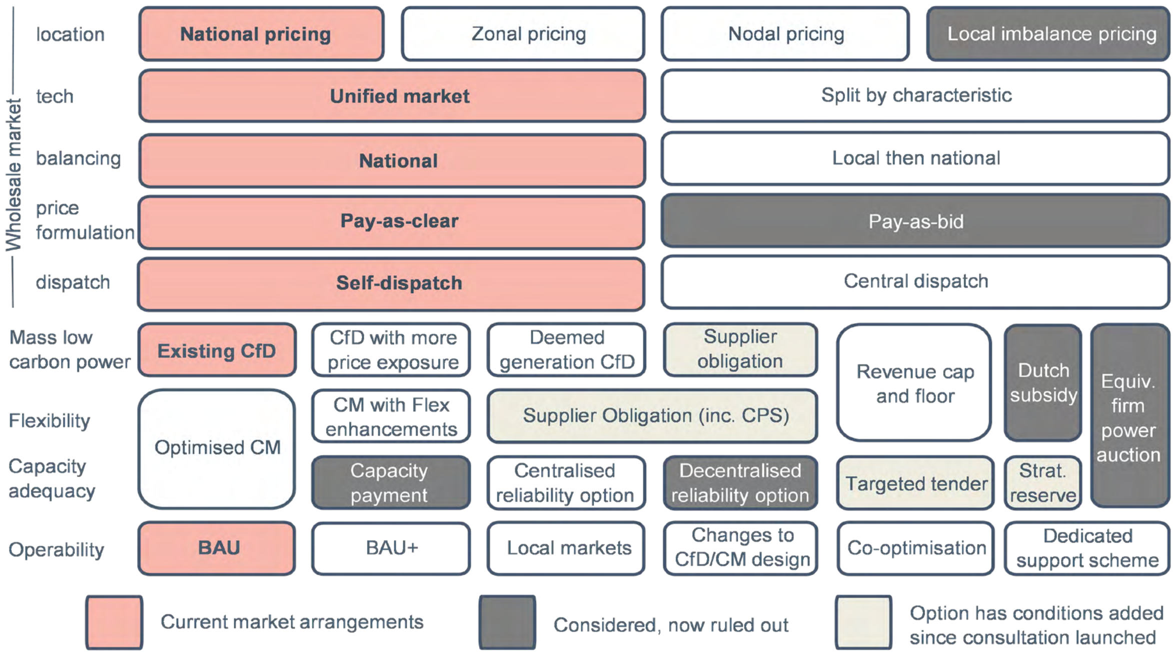
Source: DESNZ, National Grid ESO, Cornwall Insight

3.1 REMA: the story so far

The planned roll out of mass low carbon generation is too slow to replace the aging nuclear fleet due to retire.

REMA aims to establish an enduring regime which overcomes the structural market issues, while also maintaining operability and security of supply during the transition phase. The options range from big-bang implementation of wholly new processes to incremental reform of existing systems. Some ideas are well researched and understood, and others are innovative and theoretical and might not have been tested in markets equivalent to that found in GB. Following the initial consultation on the options, some have been ruled out, while others have been developed further from the initial plans, as shown in Figure 3.

Figure 3: REMA options map following initial consultation responses



Source: Cornwall Insight, adapted from DESNZ

These REMA options are being assessed against a range of criteria and packages of reform aligned with DESNZ's overall policy objectives as well as wider considerations including statutory obligations.

- Least cost - Market design solutions should offer best value for the consumer and reflect long term whole system costs and benefits
- Deliverability - Changes must be feasible within specified timescales and aim to cause the least amount of disruption possible throughout the transition, taking into account the highly complex and integrated nature of the power system
- Investor confidence - Investor confidence needs to be maintained and built, and investment risks should be borne by those best able to manage it
- Whole system flexibility - Where it is efficient to do so, market design should encourage market participants to act flexibly
- Adaptability - Market design should be adaptive, responsive to change, resilient to uncertainty, such as where commodity prices fluctuate or new technologies emerge

The March 2023 REMA consultation response summary stated that most respondents agreed with continuing considering incremental reforms to wholesale market arrangements, but were divided on the more revolutionary options under consideration. Feedback from the initial REMA consultation included concerns that more radical, revolutionary options would require change on a scale never before delivered. For example applying locational wholesale pricing has not been adopted in a market with such a mature renewables pipeline and so many stakeholders. The

Government responded that they are keen to understand the costs and benefits of such changes before taking a decision on whether they should be taken forward. Concerns about radical reform expressed by industry stakeholders centre on several themes.

- Risk of an investment hiatus if there were “too radical” a change to the current arrangements, or if policy certainty wasn’t swiftly forthcoming
- Radical reform could be resource intensive to implement
- Harmful disruption to adjacent aspects of the market, with potential for unintended consequences such as reduction of competition within markets
- New radical approaches may impose additional administrative burdens on the system and participants, including IT requirements
- Pre-empts potential output and benefits from other Ofgem-led reforms, such as revision of TNUoS

Notably, DESNZ recognised concerns around scale of change, and said that it committed to reducing complexity in energy markets. This will help to guide its package construction approach, with “more incremental reforms versus transformational ones”.

The value of the CfD scheme as a “well-established and well-understood mechanism” was noted by REMA consultation respondents, which is particularly relevant to maintaining investor confidence. Incremental reform of the CfD has been a feature of each Allocation Round, seeing material changes without an observable decline in investor appetite.

The objectives of REMA are system-wide: decarbonisation, security of supply and cost-effectiveness require synergy across the whole system. The REMA consultation response saw a commitment that decisions will be driven by whole system considerations that account for the needs of all energy market participants, with a high weighting given for future considerations. Many respondents to the consultation stressed that for participants to invest with confidence, market signals needed to be transparent, predictable and non-volatile.

4. Revolutionary or evolutionary reform?

Different approaches to reform would require different lead times, varying levels of stakeholder engagement, and present different delivery risks. A 'big bang' radical programme of change would look different to an evolutionary reform approach applied incrementally.

Plans for reform must thoroughly assess the risks and obstacles of implementation. Prior programmes of radical energy system reform are associated with substantial delays, progressive descoping, and cost overruns. Investors in the GB renewables market have expressed concern that uncertainty, particularly during a protracted reform period risks an investment hiatus.
Two of the more radical options in the REMA consultation have been widely discussed, not least because the way they operate would impact all parts of the market. For example the CfD scheme could not continue in its current form with either model.

- **Introducing Locational Marginal Pricing (LMP)** - zonal or nodal LMP would see wholesale prices vary depending on location, with a broad expectation that higher prices would be seen in areas of relatively high demand and relatively low generation. DESNZ has said that this would encourage system users to produce or consume in a way that benefits the system, with the potential for the market to resolve network congestion. Addressing REMA consultation responses, the policy would see DESNZ and Ofgem to work together to "sharpen locational signals", including considering the role of network charging, and other options for locational signalling suggested by respondents. This is a topic of considerable debate, with the move to locational pricing receiving provisional support from the ESO, but also pushback from a number of industry participants

- **Splitting the wholesale market into separate markets for variable and firm power**, which is primarily proposed as a solution to price cannibalisation, and the resulting price volatility. This approach has not been adopted by any substantial market to date. Part of this is intended to provide stronger signals for demand-side flexibility. DESNZ have said that a split market would extend the CfD approach which isolates renewables and remunerates them at their long-run marginal cost

The focus of this report's assessment is on the potential for incremental reform, recognising the appetite of investors for market stability. However, it is important to understand the reform options presented in this report alongside other proposals under REMA, as any reforms are likely to be delivered as part of a package.

While evolutionary changes from options in the mass low carbon power chapter. alone would not be able to meet all of the aims of the review, they can go some way to reducing the need for more radical reforms which risk undermining investor confidence in GB.

A strong and effective policy steer will be required to deliver significantly different outcomes to the current trajectory, whether that's via 'big bang' radical intervention or via sequential incremental change.

4.1 Revolutionary reform delivery risks – LMP and split markets

The introduction of Locational Marginal Pricing and the creation of a split market are two of the most revolutionary options in REMA. They would present significant uncertainty and complexity of implementation that risks jeopardising the acceleration of renewable deployment that is needed to achieve the target of decarbonising the power sector by 2035.

Both options are untested in a market directly equivalent to GB. The split market approach is entirely theoretical, and would likely need a lengthy development process that would be subject to some unique implementation challenges. More lessons can be learnt from other territories that have recently implemented or have considered implementing a locational pricing approach.

Implementation issues

LMP is controversial. Research to date has not allayed concerns that LMP would not deliver the objectives set out in REMA. The University of Strathclyde undertook research into how LMP might be applied in GB. They concluded that there may be some theoretical benefits from implementing LMP for some parts of the system. But they also concluded that there are likely to be challenges in delivering LMP in a way that is well adapted to the GB system and that it could put the UK Government's commitment to decarbonise the electricity system by 2035 at significant risk due to the time to implement.

LMP has never been implemented in a mature renewable market, instead having been adopted in markets prior to significant decarbonisation taking place. The level of renewable deployment in GB would add complexity to the process, with international examples typically having been markets dependent on a smaller number of dispatchable fossil fuel generators. Managing the transition to LMP with more stakeholders, more developed capacity signals, and more diverse investor types, would be more resource intensive than prior programmes, increasing the time to implement. Assuming investor appetite is maintained, the number of stakeholders and complexity from sustaining capacity will likely increase each year in GB.

Implementing LMP could take more than a decade, risking the achievability of net zero targets. Recent implementation of LMP in international markets suggests that the implementation process is complex and prone to delays. In Texas, USA, the move from zonal-LMP to nodal-LMP was discussed from 2002, with the Public Utility Commission of Texas approving the change in September 2003. While initially intended for implementation in 2006, it ultimately took until December 2010 (~8 years) for the new nodal market to be introduced. Additionally, LMP is currently being implemented in Ontario, Canada where a move to LMP was planned to be implemented 18 months after market opening in 2002, the current implementation work began in 2016 when the Market Renewal Program was launched. Implementation was previously targeted for March 2023, and the current plan is for the new market systems to go-live in Q2 of 2025 (~9 years after the program was launched).

The ESO's Net Zero Market Reform (NZMR) programme commissioned independent reports to start looking at risks and potential opportunities for LMP-type market arrangements in GB. FTI Consulting have suggested the transition to nodal market design "predominately depends on the efficiency of the stakeholder engagement" and "usually takes between 4-8 years". Estimates that implementing LMP in the GB market could take more than 10 years are not unreasonable given the comparative complexity of the GB market, and the need to maintain investor confidence during the transition through a clear programme of communication. Production of electricity from renewable technologies was 41.4% in GB in 2021 representing a large number of operators. When ERCOT introduced LMP in 2010 ~8% of electricity was produced from renewable sources.

Cost of capital

Cost of capital could increase under LMP, exceeding the potential benefits. Uncertainty in price and volume caused by LMP would increase risk to investors, raising the weighted average cost of capital (WACC) financing low carbon generation, and this could exceed the value of any system benefits. FTI Consulting's analysis on the impacts of LMP presented at an Ofgem workshop in Q4 2022, reports a "general perception" from stakeholders that WACC would rise, and used an assumption of an uplift of 25 basis points (0.25%) for CfD assets, and 50 basis points (0.5%) more generally for merchant assets. The UK Energy Research Council (UKERC) report that "many developers" are concerned that the increase would be in the range of 2 to 3 percentage points - which would be a level which would exceed the consumer welfare benefit modelled by FTI over the relevant timescales. Energy Systems Catapult (ESC) assessed international markets and concluded that LMP would likely not be an obstacle to large-scale investment in renewable energy in GB but did note that US markets have tended to rely on tradeable renewable energy certificates and tax credits to incentivise renewable investment which might not be analogous to the current or future GB market.

LMP has been taken off the table in Australia due to investor confidence concerns. After a lengthy development process (~7 years), plans to implement LMP in Australia have been dropped due to concerns that moving to a locational approach would be a disincentive for renewable energy investors. The plans stemmed from activity in 2016 which saw the Australian Energy Market Commission (AEMC) asked to review the transmission regulatory framework. Following the review, in October 2019, the AEMC recommended the creation of an LMP framework under its Coordination of Generation and Transmission Infrastructure Proposed Access Model, but this was dropped in 2020 pending a wider review from the Energy Security Board (ESB). This review led to the July 2021 proposals to introduce local pricing in constrained regions as part of its Congestion Management Model. Both proposals saw opposition from renewable developers, and in February 2023 it was confirmed by ministers that the plans would not be taken forward.

Ability to deliver desired outcomes

Locational signals alone do not significantly change siting decisions. Markets that use LMP have seen increased wind and solar capacity, but rises in capacity have also been seen in non-LMP markets like GB. However, there is extremely limited evidence that moving to LMP incentivises siting decisions sufficiently to overcome more significant deciding factors experienced in all kinds of markets, such as licencing, timely network access, consents, and planning permission.

In the Independent report of the Offshore Wind Champion, published in March 2023, Tim Pick recommended that the REMA process considers whether locational signals, both existing and new, are appropriate for offshore wind. Pick said that public bodies effectively already determine the location of offshore wind farms through seabed leasing, and that siting is also geographically constrained by resource and spatial planning considerations. As such, offering signals to locate in certain areas through LMP or other means such as TNUoS may not be suitable. This argument can also apply to other forms of generation as well such as solar or onshore wind, which are also limited in terms of resource and land constraints. Siting decisions for wind farm locations in GB are made many years in advance of construction, ~6 years for onshore, and ~13 years for offshore. The relatively long timescales associated with developing LMP, combined with the long lead time for siting decisions, create a disconnect with the urgency of the 2035 and 2050 decarbonisation targets.

In Texas, ERCOT zonal pricing was replaced with nodal-LMP pricing in 2010. The majority of grid connected wind assets were built after this transition, but remain located away from population centres of Austin, Dallas–Fort Worth, Houston, and San Antonio. Figure 4 uses data from the January 2023 United States Wind Turbine Database and the US 2020 Census Results to show the difference between where people live, and a heatmap of where wind farms are located. Approximately 75% of Texas' population lives in the area indicated by the red triangle. The population is concentrated in the cities, and the triangle is less densely populated than typical in the UK. The wind generation is predominantly deployed in the sparsely populated west Texas area (the white and blue pale dots). There may be many reasons why LMP didn't incentivise siting of generation assets closer to where people live over the last 13 years, including unrelated policy decisions and where the wind blows, but it does illustrate that LMP alone would not result in different siting decisions being made by developers.

Figure 4: Illustration showing Texas population centres (within red triangle) and location of wind generation assets (pale dots)

Sources: Cornwall Insight, U.S. Geological Survey, American Clean Power Association, and Lawrence Berkeley National Laboratory

If consequential change is necessary in all scenarios, including LMP, the efficacy of those additional measures without LMP should be assessed to see if they could sufficiently facilitate REMA's aims without the disruption and delays LMP could cause.

Congestion and grid development constraints still exist in LMP markets. CAISO in California utilises locational marginal wholesale pricing signals, and has postponed processing connection requests due being "inundated" with requests from potential resource developers. Unfortunately "[m]any of these requests are not located in areas considered optimal for additional transmission development" leading to a year long pause for some application types while tariffs are redesigned. The PJM market in the US has an open connection queue, but has warned applicants to expect delays.

Unpredictability of locational signals - Locational signals are useful to the extent they can be responded to by the necessary stakeholders. Parties can only respond if signals provide foresight with a high degree of confidence. LMP has had forecastability issues related to the inherent complexity of the market and sometimes suffered from low confidence about accuracy.

4.2 Market design decisions

Energy policy has supported renewable generation cost reductions and has brought forward a significant amount of capacity, but meeting decarbonisation targets will require even faster deployment. A range of options for mass deployment of low carbon power have been set out in the REMA consultation, the majority focus on adaptations of the existing CfD approach. This recognises the success of the CfD in providing certainty to investors and driving down the cost of capital.

Improved, reliable signals will deliver better market outcomes – e.g. unlock additional investment in renewable generation and flexibility. Revenue stabilisation via the current CfD supported a reduction in cost of supported low carbon generation projects. Improved market signals have the potential to benefit technologies that currently find it challenging to secure investment, such as emerging low-carbon technologies and flexible assets.

Market design plays a crucial role in communicating signals to energy users and generators. DESNZ highlighted the impact of limited exposure to market signals and always-on generation being unlinked to wider system benefits. A summary of specific market design options have been summarised below, drawing on the REMA consultation, as well as wider literature:

- **Siting signals** – Locational elements of wholesale prices or network charges are often cited as a way of incentivising generation to locate in areas where they would be most beneficial to the system. While locational pricing variance could influence an investment decision, other factors are likely to play a more prominent role. For offshore generation, the location of sites is typically determined by seabed leasing, and the siting of onshore renewables is typically driven by factors such as weather availability, the cost and suitability of land, planning permission. Additionally, the time to obtain a grid connection also provides a locational signal that is grounded in the ability of the network to manage the additional power flows. There may therefore be a limited extent to which additional locational signals can influence siting decisions. Another issue is the unpredictability of locational signals. To provide a sufficient signal for investment, there should be long term certainty that can be established well in advance of a project connecting. The Transmission Network Use of System (TNUoS) arrangements offer the main locational siting signal in GB, but charges are volatile and hard to predict accurately, and so the extent to which they offer an adequate long term siting signal is limited. At present, all generators bidding into the CfD auction receive the same Strike Price as other generators in their technology type, with factors such as location and the impact on constraint costs not taken into account. As such, generators will tend to locate near to their source of power, such as wind developers tending to locate their assets in Scotland where wind availability is highest. However, and because grid build has not kept pace with the deployment of renewable generation, this approach can lead to high constraint costs, as well as higher emissions due to the need to potentially curtail other low-carbon generation or dispatch fossil-fuel generation in order to balance the system. This issue has been discussed in a number of papers including Newbery, 2021 and Savelli et al., 2022

- **Dispatch signals** – It is desirable to incentivise the plant to run in a manner that aligns with the operation of the system. Currently such signals in GB are limited, and can even be dampened by the existing arrangements. For example, the current CfD arrangements limit the extent to which generators are likely to turn down their generator output as the payment mechanism is linked to the output of the generator. While locational dispatch signals could be amplified through wholesale prices or network charges, a market-based approach that offers appropriate incentives to act in a manner that benefits the system can deliver similar outcomes. This could involve opening up new markets or making improvements to the Balancing Mechanism. In combination with revisions to the CfD to remove barriers to generation participating in flexibility markets, this approach could adequately incentivise generators behind constraints to turn down and reduce costs to consumers.

- **Volume risk** – Volume risk refers to the variations between expected and actual production, caused by factors such as wind speed. This gives rise to a level of uncertainty in the achievable revenues, which can affect the attractiveness to investors sensitive to risk type. The current CfD does not allow generators to counteract the impacts of low wind availability with the higher prices that are typically seen at such times, as is seen for merchant generators selling on the spot market (those operating in the short term competitive markets). Investors and developers will take this into account when approaching the CfD and will look to price in volume uncertainty into their bids. Inefficiencies in the pricing process could lead to higher bills for consumers.

- **Intraday distortion risk** – Under the current CfD mechanism, the reference price for intermittent generation is derived from day ahead data from EPEX and N2EX. This gives the generator visibility of the CfD payments they could potentially receive, potentially impacting their behaviour. Where the reference price is below the Strike Price and a top up payment would be received, generators may price this into their bids in the intraday market to ensure they are dispatched. Where the reference price is above the Strike Price, and payments are due to be made by the generator, it may become advantageous to sell power back on the intraday market or self-curtail and pay associated system balancing costs. Distortion from the pricing mechanism could lead to generators' seeking to manage this risk, with different stakeholders' hedging strategies potentially adding to overall costs, and ultimately higher bills for consumers.

- **Limited exposure to market signals** – While a merchant generator might only run when the wholesale price is adequate to cover costs, thus aligning higher outputs with times of higher demand, the current CfD scheme incentivises generators to operate as often as they can. Where wholesale prices are significantly lower than average, indicating a situation of oversupply, the CfD backed generator would still be topped up to their contractual Strike Price, and if the system operator wished to turn down the generator, it would need to offer more than the subsidy benefit to do so. The scheme design also means that CfD generators are also not incentivised to participate in other markets or provide flexibility services, as they would need to bid high prices in order to counteract the loss of subsidy from reduced generation output. Additionally, there is no signal for the generator to schedule maintenance when prices are low and not generating would be less detrimental to the system. Limited exposure to market signals could negatively impact the ability of the system to decarbonise, and could result in pricing efficiencies being missed, leading to higher bills for consumers.

- **Uncertainty of negative price periods** – Following changes introduced for Allocation Round 4, generators no longer receive top-up payments where wholesale prices are below zero. This was intended to remove the incentive to generate when the grid is oversupplied. ‘Price cannibalisation’ occurs when at times of high output from intermittent, weather-driven generation such as solar, onshore and offshore wind, having a depressive effect on the wholesale electricity price. As more renewable generation connects and the price cannibalisation effect becomes more pronounced, the risk of such price periods increases, creating more uncertainty for developers.

- **Material changes** – The Strike Price in a CfD auction is determined in advance of construction, meaning that any material changes to the project or increases in construction costs cannot be accounted for once a CfD is in place. Developers will price this risk into their bids, potentially leading to higher than necessary costs to the consumer. Costs changing after bids have been made can also impact on the viability of projects.

- **Liquidity** – CfD payments are based on a day-ahead index, and as such generators will tend to align their hedging and trading approaches with this timeframe in order to reduce risk. While this creates liquidity in the day-ahead market, it reduces liquidity in the other markets when compared to a longer-term hedging and trading approach that would typically be seen for merchant plants.

5. Options for incremental reform

This section summarises some of the options for reform proposed under REMA, intended to address identified challenges facing the GB energy markets. Adoption of mass low carbon power generation will considerably cut environmentally damaging emissions connected with energy generation. The key drivers for reform are the need for increased low carbon generation to meet net zero, as well as a cost-effective market arrangement that offers affordable energy prices for consumers.

Current arrangements dampen incentives for optimal system operations. Market design reform offers the chance to attract investment in mass low carbon generation, and ensure customer value for money, by improving which parties are exposed to market signals such as siting signals, dispatch signals, and apportionment of volume risk.

5.1 Shortlisting mass low carbon power options

The REMA consultation set out several options to support mass low carbon power. We have assessed 6 options related to CfD reform. Two options were expanded to illustrate the effectiveness of incremental reform accompanied by strong policy direction.

- **A CfD based on deemed generation** – electricity generation plants are paid based on their potential to generate in a particular period, rather than their actual generation behaviour

- **A revenue cap and floor** – electricity generators would compete in the full range of markets (capacity, wholesale, balancing, ancillary services), and if they do not meet a minimum revenue amount, then they would be topped up at the end of the period

The 'revenue cap and floor' and the 'deemed' options are considered in detail as part of the options assessment in this paper in section 6.

Based on proposals in the REMA consultation, stakeholder proposals and academic models, a long list of reform options were identified for consideration in this report. Cornwall Insight assessed the merits of these options in order to remove any less credible options, and after discussion with RenewableUK, Solar Energy UK, and Scottish Renewables a shortlist of options was identified. This report explores a set of credible, evolutionary options, to help public discussion of the suitability of evolutionary reform. By design, the list is not exhaustive, and an option's non-inclusion should not be seen as criticism of that option.

5.2 Option 0: the current CfD

Design: CfD contracts are currently awarded via a sealed bid auction, in which all interested and eligible generators submit a Strike Price for delivery. The auction is 'pay as clear', which means that all generators in the same Pot (grouped by technology types and circumstances) achieve the same Strike Price if they are successful in the auction process (subject to the maxima and using default administrative Strike Prices). The auction established a merit order which ranks the generators based on costs to consumers and selects the cheapest within set financial budgets and capacity caps. The key price considerations for CfD contracts are:

- **The Strike Price**: Price agreed in the CfD Contract, representing the price tendered by the generator in the allocation round, stabilising revenues for investors in a particular low carbon technology. The Strike Price is regularly recalculated throughout the term of the agreement to account for the effect of inflation and transmission losses.

- **The Market Reference Price**: The market rate which is removed from the Strike Price when payment is made, consisting of either the Intermittent Market Reference Price, or IMRP (a day ahead hourly figure for intermittent technologies) or the Baseload Market Reference Price, or BMRP (a six-month price for baseload generators). This is designed to be a measure of the average market price for electricity in the GB market and is expected to be paid in the Offtaker PPA, although is subject to negotiation/

- **The Difference payment**: The Strike Price minus the Market Reference Price, which is paid within the CfD Contract

This CfD scheme arrangement means that if the wholesale price of electricity is low (if the Reference Price is below the Strike Price), then the generator receives a top up payment to the Strike Price. If the wholesale price of electricity is high (if the Reference Price is above the Strike Price), then the generator pays money back into the scheme. This encourages investment due to more predictable revenues and reduced exposure to market risks. Additionally, customers are protected from some of the shocks of high electricity wholesale prices.

Figure 5: CfD model showing relationship of Strike Price and resulting wholesale price

Source: Cornwall Insight

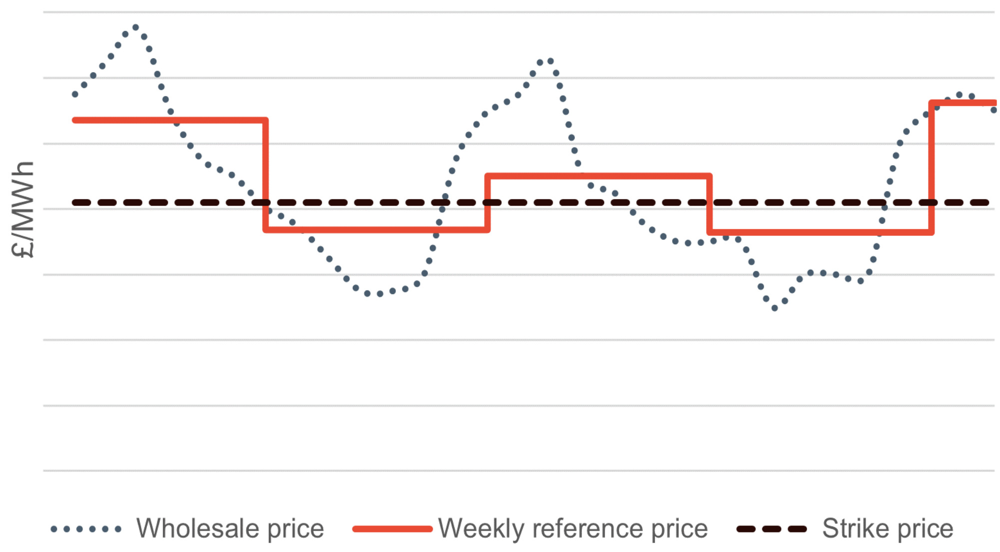
Benefits of the current CfD arrangements

- Reduced cost of capital for generators, delivering lower lifetime costs
- The competitive auction approach is established and understood
- The private contract format offers certainty for investors with low risk appetite
- The scheme can evolve between allocation rounds
- The auctions interact with contemporary market forces

5.3 Option 1: Longer average reference price period

Design: Under the existing CfD arrangements, the reference price is based on the GB day ahead hourly price. Instead, a longer price period could be used, such as a weekly or monthly average.

Figure 6: Example of CfD design with weekly reference price period



Source: Cornwall Insight

Key advantages

- Similar processes to current scheme
- Increases exposure to market signals via pricing range
- Maintains incentive to maximise generation

Key disadvantages

- Doesn't address volume risk
- Unlikely to have significant impacts on operating parameters

As the option is a relatively small departure from the current scheme design, it should be relatively simple to implement, with limited changes needed for non-generator stakeholders such as the LCCC and suppliers. Having a longer reference price period could be more interesting to electricity generators over other options as it allows for minimal deviation from the current process. However, one of the drawbacks from this design is that the bidding strategy is likely to be more complex, for generators, DESNZ and any scheme administrators. Generators would need to re-configure a bidding strategy and long-term price forecasts, and the DESNZ would have to be able to forecast the IMRP for the auction and valuation process. Compared to challenges with other designs, this is likely to have a low impact for generators.

The impacts would also depend on how the reference prices are set. The consultation has mentioned a "weekly average". If this is an average of trades on an exchange (i.e. EPEX), then there is additional risk for generators, as their output figures will impact revenues.

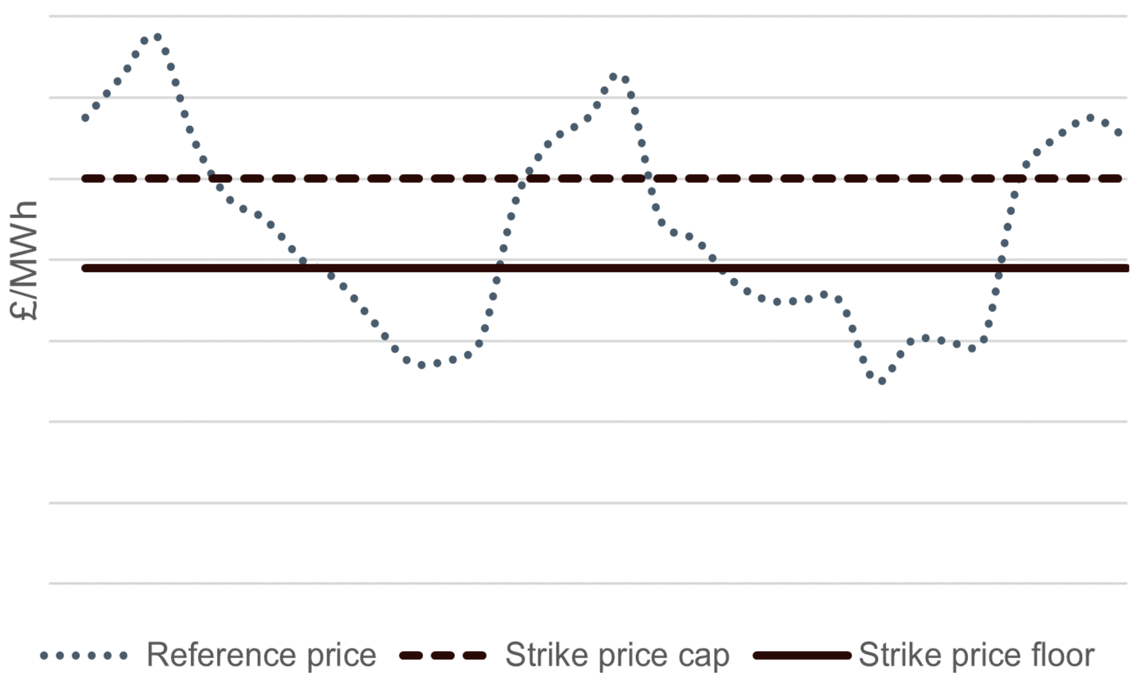
It is currently unclear what the level of benefit to the network longer reference price periods would bring.

The design allows for increased market exposure, creating a higher risk for generators, but is unlikely to sufficiently change operating parameters for generating assets without substantial additional reform.

5.5 Option 2: Strike Price range

Design: The existing CfD design uses a single Strike Price. Generators then receive or pay the difference between the reference price and the Strike Price. An alternative option would be to use a Strike Price range. This would see generators receiving payments up to a Strike Price floor, but only paying back when the reference price exceeds a Strike Price cap. If the reference price fell between the cap and floor, then no difference payments would be made.

Figure 7: Example of CfD design with Strike Price cap and floor



Source: Cornwall Insight

Key advantages

- Increases generator exposure to market signals when prices are between cap and floor
- Could allow some passthrough of change in project costs

Key disadvantages

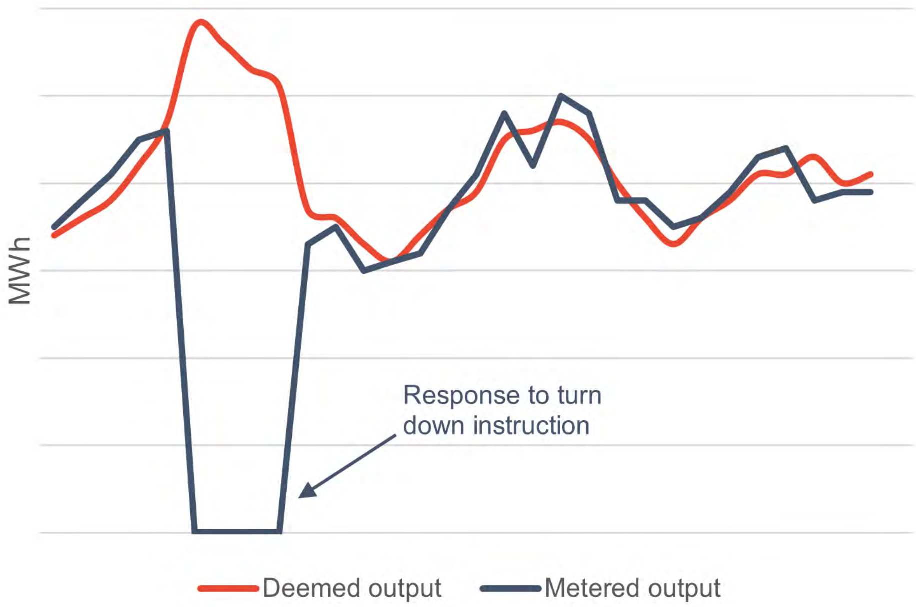
- Maintains incentive to maximise generation output when this may not be beneficial to the system
- Doesn't address volume risk
- Unlikely to have significant impacts on operating parameters
- Increased investor risk in the reference price range could lower certainty and increase bid prices

This option could increase the benefits to generators. A set Strike Price could be augmented with a floor and a cap price. There are different approaches possible. One option would see a floor price securing minimum price per unit of output linked to an investor's cost to service debt, and an upper cap price based on a unit price allowance set at a level that allowed a return not considered “excessive”. A Strike Price range means a generator could reduce exposure to changes in project financing costs during the development phase. However, the approach could increase the complexity of the scheme, with a number of elements to be explored. For example, it is not clear how prices would be set in the auction. While single Strike Price bids are relatively simple to assess, having to determine the outcome of an auction based on both a cap and a floor would be more complex, with challenges around the setting of the delta between the cap and floor. For example, a site could have a lower floor but a higher cap than a site with a narrower range, and there would be a need to determine which would deliver the best outcomes. This would require detailed central modelling, and participants would also need to take account of this complexity. Another option would be to set a standard delta, either as a fixed £/MWh value, or as a percentage of the floor price. Once a cap and floor are obtained, generators may also find it more difficult to determine the most appropriate trading strategy in order to maximise revenues in the most efficient manner. Fairness must be considered when determining the risk allocation between the billpayer and the investor.

5.5 Option 3: Deemed output

Design: Under current CfD arrangements, the generator makes or receives payments based on its actual generation volumes. However, this incentivises the generator to run when market prices are lower than the true marginal cost of running, shielding it from market signals and giving rise to dispatch distortions. An alternative is to deem the output of the generator. There are a range of ways that this could be done, including assessing the output of similar generators. Whether the deemed volumes apply to the generator could also depend on the availability of the assets. For example, if the site was unable to generate at a particular time, then it would not have the deemed volumes applied. By removing the incentive to maximise output, the option would allow generators to turn down their output without affecting the payments they receive. There would still be the use of a reference price, and so it is expected that generators would still look to align their market revenues to those that would be achieved by matching the reference price.

Figure 8: Comparison of deemed and metered output approaches



Source: Cornwall Insight

Key advantages

- Provides full exposure to market signals
- Generators likely to be more willing to participate in balancing services
- Addresses short term volume risk

Key disadvantages

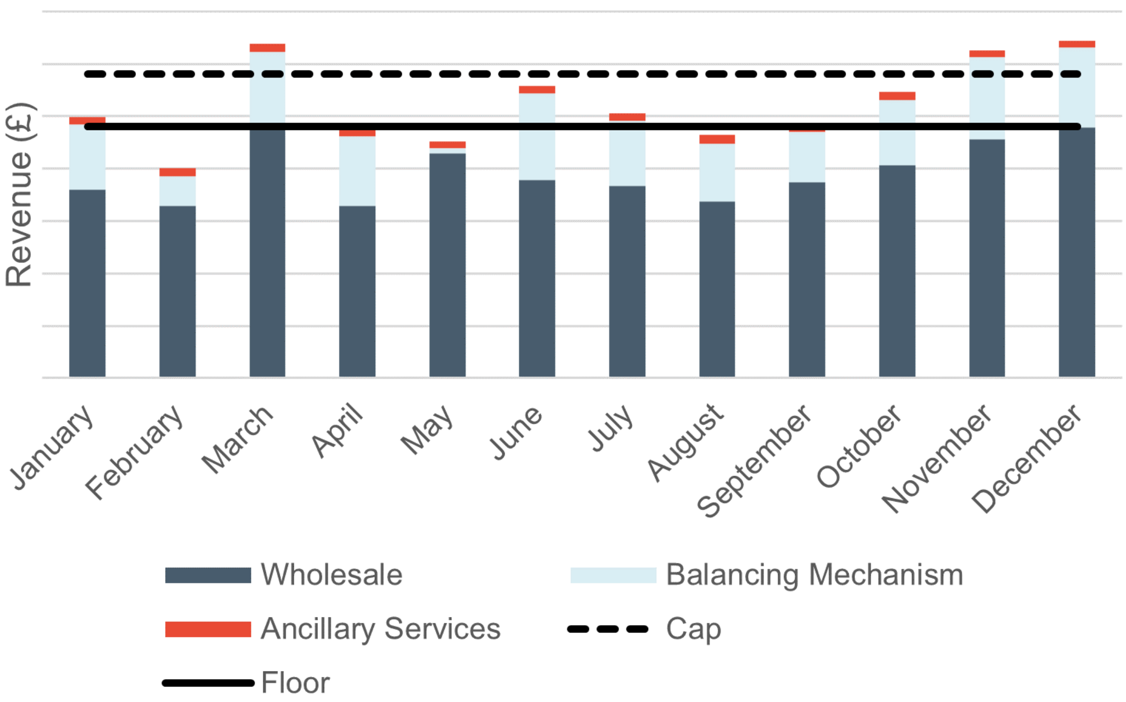
- Risk of non-delivery higher
- Complexity of determining deemed output
- Consequential impacts on non-deemed generators
- Challenging to reflect future technology changes such as improving load factors

There are several variations of the deemed output approach, with the potential for use in combination with other reform options. For example, deemed output payments could be made based on a single Strike Price, but the approach could also be used in conjunction with a cap and floor. The generator could also receive a fixed price, subject to meeting a certain level of availability over a particular period.

5.6 Option 4: Revenue cap and floor

Design: The CfD currently guarantees a payment based on the output of the generator, but an alternative would be to provide a guaranteed minimum and maximum revenue for a determined period. This would allow the generator to participate in a range of markets and receive payments if the floor revenue was not achieved. Conversely, if the generator's activities exceeded the revenue cap, the generator would pay back the difference.

Figure 9: Example of revenue cap and floor approach



Source: Cornwall Insight

Key advantages

- Provides some exposure to market signals
- Addresses volume risk and providers more revenue certainty
- Increased risk in calculation process

Key disadvantages

- Potentially reduces incentives for good siting and asset improvements

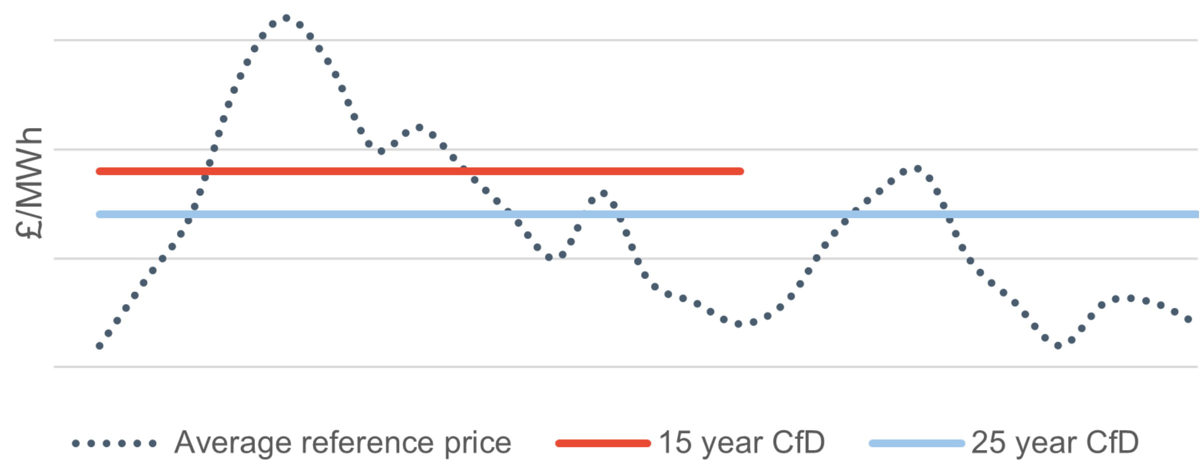
Percentage share variations: A variation on the cap and floor would see the generator topped up to the floor revenue allowance, and while it would be able to achieve revenues above the floor, it would be expected to pay back a percentage of these, effectively sharing any additional profits with consumers. A "soft cap" could also be used, allowing the generator to keep all revenues above the floor and up to a cap, above which only part of the revenues would be retained. This is intended to ensure that projects are still incentivised to optimise revenues and continue to provide power and other services once the cap has been reached.

5.7 Option 5: Longer agreement durations

Design: CfDs typically run for 15 years (or 35 years for nuclear). However, assets are expected to outlast the duration of the contract, meaning a "merchant tail" without any support. Uncertainty around post-support prices can impact on the cost of financing and increases risk for investors. Providing a contract reflective of the lifespan of the assets could reduce risk and lead to lower Strike Prices, and would offer more protection against cost uncertainties such as operation and maintenance, replacement costs, and network costs. The approach would lead to shorter merchant tails (the period at the end of the asset's life without subsidy), which would reduce the risk premium factored in to prices.

The potential for increased costs over the lifetime of the contract may outweigh the benefits. However, it could be argued that when deployed in conjunction with the existing portfolio of 15 year agreements, the option provides a potential hedge against future price increases, providing additional protections to consumers. However, as there is a risk of the overall costs being higher, this option is likely to face low levels of support from Government, especially as the current CfD scheme has been seen as a success story in driving down the costs of renewables.

Figure 10: overview of longer agreement durations approach



Source: Cornwall Insight

Key advantages

- More reflective of asset lifetime
- Reduced risk for investors

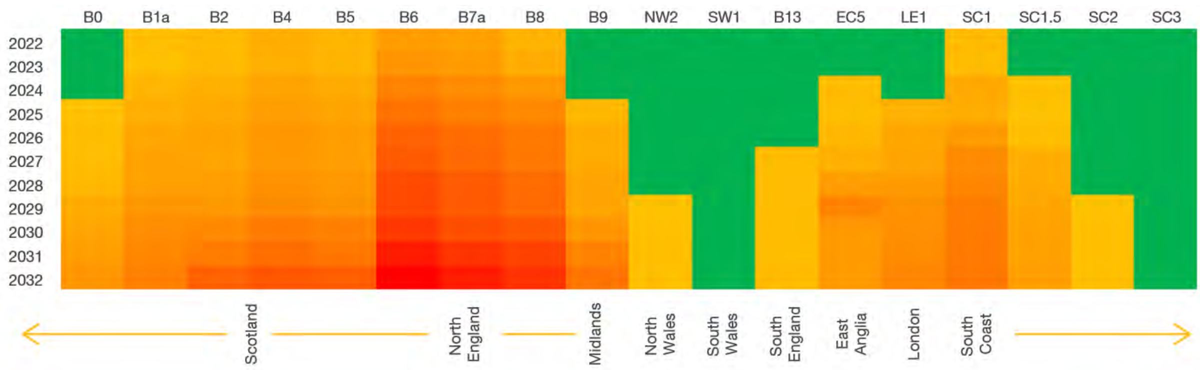
Key disadvantages

- Likely to be unacceptable to government due to risk of higher cost to consumers

5.8 Option 6: Locational CfD

Design: While the current CfD scheme takes a national approach, principles of zoning could be introduced to offer different prices based on a range of factors such as proximity to demand. This could take a variety of forms, including separate pots or auctions for different regions, or locational scaling factors reflecting the value of siting assets in different areas, or the extent of constraints in an area (see Figure 11). A variation of the locational CfD has been proposed by *Savelli et al., 2022*, this option would internalise balancing costs into the CfD Strike Price in order to provide signals for assets to locate where they can provide most value from a system perspective.

Figure 11: Excess flows beyond boundary capability in the absence of reinforcement



Source: National Grid ESO

Key advantages

- Incentivises generation to locate in areas more beneficial to the system
- Provides additional locational signals beyond TNUoS, offering some of the benefits of LMP without directly affecting the wholesale price

Key disadvantages

- Potential to disincentivise investment in areas most suited to renewables
- Complexity of bidding could be off-putting
- Difficulties in forecasting appropriate locational prices across CfD timescales
- CfD awards occur many years after siting decisions were made

5.9 Compatibility with REMA – LMP

REMA assessment criteria	Description	Criteria compatibility with LMP	
Least cost	Market design solutions should offer best value for the consumer and reflect long term whole system costs and benefits	Risk of rising cost of capital and implementation timelines negatively affect cost assessments	
Deliverability	Changes must be feasible within specified timescales and aim to cause the least amount of disruption possible throughout the transition, taking into account the highly complex and integrated nature of the power system.	Does not support 2035 decarbonising power system target	
Investor confidence	Investor confidence needs to be maintained and built, and investment risks should be borne by those best able to manage it.	Drawing on the recent Australian experience, maintaining investor confidence is challenging	
Whole system flexibility	Where it is efficient to do so, market design should encourage market participants to act flexibly.	LMP could be designed in a way that would support whole system flexibility	
Adaptability	Market design should be adaptive, responsive to change, resilient to uncertainty, such as where commodity prices fluctuate or new technologies emerge.	Assuming market participants can meaningfully engage and react to complex market signals derived under LMP	

The split market option has not been implemented anywhere at scale, so there is an extremely limited evidence base available for analysis. Strengths include the potential to set out a detailed market design relatively quickly, providing certainty for investors. Areas of concern include the likelihood of market illiquidity removing market efficiencies, ultimately driving up costs for consumers.

It is worth noting that all options will require substantial network reinforcement, and the outcome of REMA will not remove the need for upgrades. The September 2022 Net Zero Electricity Market Design Expert Group report from the Climate Change Committee identified "the biggest challenge of the 2020s" and included mobilising investment needed in networks in that list.

Additionally, other network issues such as significant wait times in the connection queue will also need to be addressed. Avoiding transmission network upgrades by shifting generation closer to where more people live will need to consider that new assets may already be waiting in a queue in that area.

5.9.1 Net Zero, Challenges beyond REMA

Scaling up volumes of low carbon generation is not solely a matter of adjusting conditions for investors or shifting the generator's operational signals.

Planning processes must be reformed, to operate in conjunction with energy policy. National and local governments are responsible for ensuring laws and procedures allow for optimal and timely deployment of renewable generation at scale.

The current connections process, designed two decades ago for a small number of fossil fuel generators, is widely acknowledged as inadequate. Increasing application volumes, new types of connection customers, significant changes to the technology mix, greater interaction between transmission and distribution networks, complexity and uncertainty in network investment planning, have left an urgent need for a holistic whole system approach to planning network investment. Various groups have set out the case for urgent reform, including National Grid ESO's Connections Reform Case for Change report and June 2023 consultation, the Energy Network Association's Strategic Connections Group Action Plan, and UK Parliamentary debate.

Changes to onshore wind planning policies remain subject to political support. The Scottish Government's National Planning Framework 4 (NPF4) sets out sustainable policies intended to support increased renewable energy generation, and notes this would require changes to planning. The UK's Department for Levelling Up, Housing & Communities have published a consultation seeking views on its proposed approach to updating the National Planning Policy Framework (December 2022). This includes proposed changes to planning policy for onshore wind to deliver a more localist approach that provides local authorities more flexibility to respond to the views of their local communities. Changes to the framework were proposed to fulfil the commitments set out in the British Energy Security Strategy to support the repowering of onshore wind and to review the barriers when installing energy efficiency measures. Ahead of an anticipated General Election, the Labour Party have said their policy in their first year includes updating the National Planning Policy Statements to remove barriers to onshore wind.

6. Case studies: Deemed output and Cap and Floor CfD models

To determine which options to consider further, an assessment was undertaken based on the following criteria:

- The level of **investor confidence** that the option would support. The existing CfD is well liked and well understood by investors, supporting significant levels of project funding in return for longer term revenue certainty. It is therefore important to consider how the options would impact on investability in GB and whether they could support the necessary deployment of generation assets required to meet decarbonisation ambitions.

- The level of **evolution** and extent to which the option would represent a departure from current scheme arrangements. While REMA has the potential to deliver large scale reforms, there is also merit in lower risk options that can still deliver the right outcomes. As such, options with fewer implementation barriers that represent more of an evolution of existing arrangements were scored more highly. Lower scoring options requiring significant change may still have merit, if they correspond to a high degree of efficacy and materially better outcomes.

- The **cost/value** of the option. With the CfD being funded by consumers, an important factor to consider is the extent to which the options would deliver the desired outcomes of reform while keeping costs to consumers as low as possible. DESNZ have confirmed the importance of considering overall system value in REMA and that 'least cost' should not be conflated with a short-term cost minimisation that is not suitable for an enduring approach.

Under this approach, and in discussion with RenewableUK, Scottish Renewables, and Solar Energy UK, the shortlist in section 4 was narrowed down to focus on the deemed output and cap and floor models for more detailed analysis. The two selected options demonstrate the potential for incremental reform. Achieving net zero goals would require additional changes and complementary initiatives as is the case with all identified options for reform within REMA.

The merits of these options are considered from a range of perspectives. Both options see payment at least partially decoupled from output, incentivising more flexible behaviour from generators and allowing participation in multiple markets without removing the principle of revenue certainty that investors identify as essential for keeping cost of capital lower.

The options have been scored against a range of assessment criteria:

- **Net zero** – Will the option help to support decarbonisation objectives as set out in REMA?
- **Cost reflectivity** – Will the option ensure value and risk are fairly apportioned, considering the whole system benefits and costs?
- **Investability** – Will the option maintain or increase investor appetite in GB? Could the option cause a hiatus in investment in GB low carbon generation?
- **Future proofing** – Will the option be able to respond and adapt to future market developments?
- **Implementation ease** – How long will the option take to implement? How costly will it be? What changes will be required from industry? How compatible is it with Government policy?
- **Impacts on consumers** – What will the impact be on the consumer bill? Would it restrict the reliability of the energy supply?
- **Impacts on generators** – How will existing and future generators be affected by the changes? Would the processes or supporting systems be more complex or expensive to maintain?

The assessment is made against a no-change option where the current CfD scheme continued as currently described. If an element is expected to be no better or worse than the existing scheme it is assessed as 'neutral'. A positive assessment would be given to a model that is considered an improvement to the current CfD scheme and a negative assessment would be given to a model that results in a reduction in whole system benefits compared to the current scheme.

Negative	Neutral	Positive

6.1 Deemed output CfD – detailed assessment

Whereas the current CfD incentivises generators to run whenever possible, under the deemed output approach exporting energy would not be needed in order to guarantee payments. Instead, generators would be able to participate in other markets, such as the Balancing Mechanism, knowing that any potential top-ups would be unaffected. This would provide a number of benefits from a system operation point of view, as payments to turn down CfD generation would no longer need to exceed the value of the subsidy payments. Generators would also be able to innovate to provide other services.

A number of issues arise from the deemed output approach. These include the challenge of determining how to calculate the output, with a risk that payments may not be reflective of availability without proper monitoring. While there have been suggestions that reference generators in similar locations could be used, this itself presents issues, as sites are unlikely to be similar, and it risks creating perverse outcomes between CfD and non-CfD generators. Another option would be to use a modelling approach with on-site condition monitoring, but ensuring the accuracy of this approach may also be challenging. A central body would likely need to take responsibility for verifying the accuracy of deemed outputs, which could add an additional cost and administrative burden. The extent to which generators would be more willing to turn down in order to receive payments is uncertain, with several potential barriers including the willingness to engage in more complex markets, and the impact of such activity on the condition of the assets through degradation. The timeliness of any true-up activity will inform the attractiveness of a deemed CfD scheme to operators.

The additional complexity from introducing a deemed element to the CfD scheme would be offset by longer term certainty for investors, and the overall familiarity with the core scheme. If this approach gains industry consensus, the deemed output approach has the potential to bring significant benefits.

An assessment of the deemed model against the assessment criteria is below.

Criteria	Assessment	Score
Net zero	The existing CfD has been successful in driving the deployment of low carbon generation, and retaining the scheme, albeit with changes to the determination of output, would help to provide a route to market that appeals to investors and provides value for money for consumers. With the use of deemed output, assets would be more willing to turn down, which could help to tackle issues in generation constrained areas. In turn, this could facilitate more connections for low carbon technologies. Note that this would not resolve constraints costs completely, with the majority of costs stemming from the turn up of dispatchable generation. The option provides more opportunities to participate in other markets without affecting subsidy payments, and so generators are likely to be more willing to deploy co-located storage e.g. batteries, hydrogen, helping to support a more flexible system. Issues with price cannibalisation leading to insufficient revenues are still likely to persist, with times of peak deemed output expected to correlate with lower wholesale prices. However, the overall effect may be depressed due to more willingness to turn down and the other available revenue streams.	Positive overall
Cost reflectivity	Decoupling difference payments from actual output increases the level at which the generator is exposed to market signals. This helps to tackle issues around high curtailment payments, giving the ESO the ability to make turn down payments that are more reflective of the overall market conditions. With the likelihood of differences between what was actually generated and the deemed output, subsidy payments may not necessarily reflect the behaviour of the generator during normal operation, reducing alignment with the rest of the market. If the deemed output were consistently under or overestimated, depending on the alignment with the reference price, could result in better or worse value for the billpayer.	Conditional, scheme details TBC
Investability	Volume risk is seen as a major uncertainty for investors, and this would be addressed to some extent. However, there would still be uncertainty as the deemed output would be reliant on modelling, reference generators, or other calculation methods which could be influenced by a range of factors. There may be concerns that the arrangements could result in less optimal siting decisions or discourage developers from taking steps to improve actual output. However, siting is predominantly determined by planning and leasing decisions made prior to investor's engagement. A move to a deemed CfD would not materially impact developers' exposure to locational signals when compared to the existing CfD regime. This could affect the approach that investors take and influence the risk appetite for entering into the CfD. Risks around inaccurate benchmarking may also be factored in, which could be addressed by developing a robust methodology with scope for ad hoc adjustments if needed. The additional complexity of determining deemed output and the potential for additional costs arising from monitoring and verifying availability may be a barrier to some.	Net positive, recognising additional complexity
Future proofing	Using the deemed approach should be fully adaptable to future system requirements and technology capabilities. In a similar manner to the existing CfD, newer capabilities or emerging technologies could be allocated to existing pots, or new pots could be created, allowing technology-specific factors to be considered. One drawback is that brand new technologies may have less certainty over what their deemed output calculation might be, with less data available on typical outputs, however REMA acknowledges that these are likely to be incentivised during the initial phase by alternative methods and are therefore out of scope. Recognising the existing CfD already includes a generally flexible approach to future proofing this adaption increases the potential to add to the incentives for co-location, the option could support a more integrated future power system. There may need to be a consideration around the impact on the rest of the market if more generators become subject to the deemed approach, ensuring data was available to allow for balancing and revenue management across the generation chain.	Builds on existing CfD foundation

Implementation ease	The impact on the design of the scheme itself should be relatively minimal. The only change would be the move from metered output to deemed output, and the majority of the CfD arrangements would stay in place with the auction process unaffected. The approach to determining deemed output would be more complex, with factors such as site location, weather variables, and site configuration potentially needing to be modelled and verified. There are several potential options for doing this, and careful consideration would be needed to determine the best approach. Establishing a balance between process efficiencies, and maintaining confidence in the efficacy of the scheme will be necessary. On-site condition monitoring, where the performance of the asset is continuously monitored to determine its output could use be comparable to the current scheme. Monitoring equipment, including metering, offers information for assurance. This data could also be used to refine the design of future allocation rounds, to ensure value for money was achieved on behalf of the billpayer. However, investors would need to be assured about the fixed nature of each auction's terms, that the measurements would not be used to retrospectively change the terms of the arangement, or the cost savings derived from the scheme's long term certainty would be eroded. Output data from reference generators in similar locations could be used as a basis for determining deemed output. However, finding truly comparable reference generators could be challenging as sites are unlikely to be identical, and may create an incentive for the potential of sites for development as the volume risk would no longer be born solely by the operator e.g. onshore windspeed can vary within relatively close proximity. Establishing an independent body or assigning an existing organisation to oversee the setting and monitoring of deemed outputs is another option. This would involve regulatory oversight and verification processes to ensure transparency and fairness in determining the deemed output. Lessons learned from the current CfD scheme, and programmes such as encouraging wider access to balancing services for newer and smaller operators, could be drawn upon to ensure the processes didn't unduly prevent market participation. Across projects feedback has been consistent that clear and transparent rules, timely access to information, and clearly defined roles will help encourage engagement from new parties. The LCCC's remit could be expanded to include this type of monitoring. The Energy Security Bill will grant Ofgem a new strategic role in the regulatory codes and other powers. Assuming a licensed code regime follows, and reform of the type explored in Ofgem's April 2022 consultation takes place, one of the new licensed code bodies may be suited to take on this responsibility – for example the equivalent of the current BSC regulations could be expanded. A wholly separate body could be set up to oversee the setting and monitoring of deemed outputs, although this may require additional resource to maintain. The most suitable option would depend on factors such as accuracy, feasibility, transparency, and cost-effectiveness. Careful consideration and evaluation would be necessary to determine the best approach for determining deemed output in the scheme, along with accurate cost estimation for operators and the monitoring body. With the option remaining market based and providing a hedge against changing power prices, it is likely to be politically palatable, although there would be a need to demonstrate a clear benefits case. However, there is concern that making payments based on deemed output could be seen as paying for generation where it is not beneficial to the system, or "double paying" where the generator has received turn down payments from the ESO. While payments could be limited during periods of excess generation output or where generators have turned down, this would likely lead to higher Strike Prices which would counteract any consumer savings. Overall the deemed approach could better align with Government policy outputs on improving total system costs, benefitting from implied and direct policy support.	Net neutral
Impacts on consumers	Balancing costs that are passed through to consumers should be reduced by correspondingly lower constraint payments. This could help to address perceptions around inefficiencies of public investment. Some public disquiet about constraint payments has been identified in the press. This could erode confidence in the transition to net zero if left unresolved. Minimising the perception of waste, if accompanied by genuine system benefits, could help consumers better understand and support the energy transition. The incentive for co-location of storage could see more non-controllable generators exporting at peak price periods, helping to drive down costs.	Positive impact

Impacts on generators	The deemed output approach allows for better flexibility and enables generators to respond to a wider range of market signals. The use of availability metrics could have a significant impact. For example, if a fully deemed CfD was used without taking into account actual availability, and the generator was unable to run, then it would be exposed to difference payments based on deemed output. If the reference price was above the Strike Price, then this would expose the generator to significant risk but could also offer upside where the reference price was lower. Using availability metrics would help to overcome this issue and be more reflective of generator outputs without having a significant impact on behaviour. New revenue sources would be available without risking subsidy payment, encouraging behaviour that corresponds with overall system benefits. It may become more complex to operate under a deemed CfD due to the additional revenue streams that would be available. While a generator could still choose to maximise output, this may put it at a competitive disadvantage with other deemed CfD plants. Smaller generators and operators may be deterred from engagement in the CfD scheme, but the relative complexity of the bidding process and eligibility of the current scheme would be unlikely to result in a reduction in the number of participants. Third parties and experienced operators may be able to provide services to help new entrants – much as they do in the current scheme.	Overall positive
Other considerations	De-coupling payments from output has the potential to allow more opportunities for planned downtime and maintenance, potentially synchronised with system needs. In optimal conditions this would help extend the lifetime of assets, achieving the best lifetime value for investors and consumers. The reconciliation process and regulation would add complexity. The transfer of funds between generators and energy suppliers is currently very swift. The potential for a more complex methodology for setting CfD payments could see appeals and delays, potentially disrupting revenue flow. Depending on the approach to deeming outputs, there is the potential for abuse in the absence of robust verification. Any move away from traditional metering of output over time would be less familiar to most actors, and could promote genuine disagreement especially in the introductory period. Participants could seek to exploit loopholes in new rules or ambiguities in the scheme's design to challenge on strategic grounds or gain unfair advantages. The purpose of a revised CfD scheme will be to incentivise different behaviour from generators, so the scheme design would need to be tested against rational maximising by operators. This could range from the helpful - timing generation to coincide with peak price periods – to actively harmful, such as seeking to influence reference generators used for deemed output calculations. Competition law around price fixing are deterents to some of this behaviour, as are existing whistleblowing channels. Clarity around scheme rules, and a willingness to revise scheme rules between each allocation round to reflect the nature of any emerging technologies and the changing needs of the system, would increase the liklihood of ensuring value for money for consumers over the long term while retaining the cost benefits investors gain from the certainty of each contract. Establishing a robust system for collecting accurate and reliable data from scheme participants, which is independently tested and verified can evidence compliance with scheme requirements. Taking a risk based approach to auditing allows monitoring resource to be focused on outliers, or unexpected and unexplained patterns of behaviour. Stakeholder engagement during a trial phase, and regular evaluation and review of the initial allocation round, will help inform optimal future scheme design. The option would likely be incompatible with wholesale nodal pricing were it introduced, as would most CfD models. The CfD auction process would be near impossible for investors and generators to navigate, resulting in insufficient liquidity. The Balancing Mechanism has illustrated the scale of operator engagement, and the benefits that can be achieved by a more flexible approach. Batteries and storage are forecast to play an increasing role in the future energy system. The Climate Change Committee view 11GW in their 2035 scenario, although 35GW is already in some stage of planning. A deemed CfD approach could help accelerate that transition to low carbon dispatchable generation.	Mixed, overall positive

A consultation will help gauge stakeholder perspectives and concerns about the proposed changes to the CfD scheme and the use of deemed output to determine difference payments.

- A Deemed approach could apply for the duration of the CfD, or could be triggered in certain circumstances (hybrid). Would removing volume risk in certain circumstances, help address dispatch distortions in the scheme?
- Should any ancillary services, or additional revenue streams be excluded for eligibility in a Deemed CfD?
- Will a Deemed approach encourage the deployment of co-located storage technologies supporting a more flexible system? Could assets subsidised via a CfD have a negative distorting effect on other markets e.g. competing with revenue streams for non-CfD flexibility assets?
- Will retaining the CfD scheme with changes to the determination of output provide a route to market that appeals to investors?
- How would decoupling difference payments from actual output, exposing generators to increased market signals, impact the behaviour of generators? To what extent will amending volume risk rules of the CfD scheme significantly influence siting decisions for energy projects, or are factors such as licensing, permitting decisions, network connection availability, and Pot eligibility rules more substantive determining factors?
- Would decoupling difference payments and aligning incentives to market signals be more or less attractive than increased exposure to negative pricing periods? Negative pricing periods are ineligible for payments under the recent CfD scheme rules and are likely to increase with the growing penetration of solar and wind generation.

6.2 Revenue cap and floor CfD – detailed assessment

Like the deemed output approach, the revenue cap and floor helps to incentivise generators to participate in other markets and demonstrate flexible behaviour, rather than just maximising output. With the potential for greater revenues to be achieved by participating in multiple markets, generators would instead be able to vary their activities and offer a wider variety of services in order to go beyond the floor level. As with the deemed CfD approach, this also gives rise to system operation benefits, due to an increased willingness to turn down.

There would need to be careful consideration around the setting of the cap and floor. The floor would need to be low enough to encourage generators to maximise revenue opportunities by providing a range of services, and the cap would need to be set in a manner that maintains that incentive for the full duration of the contract. Complexities would also need to be overcome in the process for allocating contracts and determining which cap and floor deals would deliver the best value for consumers.

Criteria	Assessment	Score
Net zero	The existing CfD has been successful in driving the deployment of low carbon generation, and retaining the scheme, and adapting the scheme as a revenue cap and floor, would maintain some level of continuity for investment in renewables. By including multiple revenue streams under the cap and floor, generators would be more willing to provide a range of services, helping to provide more system benefits. Like the deemed output option, this could help to address issues in generation constrained areas, which could facilitate more connections for low carbon technologies. Generators are also more likely to be more willing to co-locate batteries in order to maximise their revenue opportunities. It is worth noting that uncertainties exist around the potential revenue streams, and investors will price this into their desired floor price. Issues with price cannibalisation leading to insufficient revenues are still likely to persist, with generators still likely to want to sell on the wholesale market at times of high output. However, the overall effect may be depressed due to more willingness to turn down and greater participation in other available revenue streams.	Improved
Cost reflectivity	On an individual basis, if an asset had its revenues topped up or it paid back revenues, the total revenue received may not reflect the market value of the services provided.	Less effective
Investability	The option would guarantee a minimum revenue, with opportunities to exceed this depending on the appetite to engage in multiple markets. This would be attractive to low risk appetite investors, as both volume and price risk would be reduced. The use of a soft cap would increase the scope for investors looking to maximise revenues by optimising their plants and taking advantage of multiple revenue streams. The arrangements have the potential to reduce the incentive to identify the optimal site, or could discourage developers from taking steps to improve actual output. Although this risk would be mitigated by clear market design, and the investors' ability to obtain revenues above the floor level should help to mitigate this. The allocation process would likely be more complex than the current CfD, which could present a barrier for some investors. The determination of an appropriate cap and floor would affect investment decisions, and will be set with consumer value for money over the lifetime of the scheme also in mind. The evaluation and assessment of bids may become more complex in order to consider factors difference payments and the draw of other markets. This increased complexity may present a barrier for some investors, especially those with limited resources or newer investors with less familiarity with the existing auction processes. Exposure to additional market signals will require further expertise by operators. Competetive market dynamics hinge on a minimum number of interested parties for each auction to put downward pressure on prices, and achieve full volume allocation, so the impact on a relatively small number of investors being deterred should be considered. Overall, this approach is more aligned to the Government's net zero policy and could benefit from direct and indirect policy direction.	Overall positive

Future proofing	The cap and floor mechanism should be able to take into account future system requirements and new capabilities from existing technology, and once established new technology. If new revenue streams opened up there may be a need to reconsider cap levels if there is a risk that generators might not provide beneficial services on top of their existing revenue streams. With more incentives for co-location, the option could support a more integrated future power system. There needs to be a consideration around the impact on the rest of the market as more generators become subject to the cap and floor, with the potential for perverse incentives to participate in markets. Minimal levels of engagement, for example evidenced by credible bids/offers, could be required to achieve the supported revenue amounts. Operators will rationally seek to maximise their revenue less operating costs and any model will need to be tested with that approach in mind to assess overall value for money for consumers. Potential loss of, or addition to capacity in alternative schemes will included in a system wide cost benefit analysis. The risk of an operator being locked in to current behaviours in a cap and floor revenue schemes, without reference to system needs or potential innovation and upgrade opportunities, is reduced compared to the current scheme, although would not be nil. During the transition to new arrangements corresponding markets would need to support to incorporate potentially new market entrants – although the annual nature of the CfD scheme would likely see any impact softened by gradual change.	Subject to mitigating consequential market impacts
Implementation ease	With similarities to elements of both the existing CfD and the interconnector cap and floor mechanism, the option does have some precedents to draw upon when considering implementation. However, some challenges do exist. The auction process would be more complex when compared to the existing process for the same reasons noted in the Investability section. There would need to be considerations around how to set the cap and floor, this being more difficult than assessing single Strike Price bids. Suitable training and modelling support would need to be available to the scheme operator and relevant regulatory and auditing bodies. Careful design and calibration of the cap and floor mechanism are essential to strike a balance between providing revenue stability and incentivising cost efficiency, innovation, and market responsiveness. Regular evaluation and monitoring of the scheme's effectiveness and adjustment of the cap and floor levels between allocation rounds can help mitigate potential unintended impacts and optimise the outcomes of the scheme. Aspects of the auction unrelated to price, such as eligibility and qualification are likely to remain unchanged. Identifying early on which additional revenue streams would incentivise the intended generator behaviour, without adding additional complexity or administrative burden, will help simplify the scheme. This will be particularly helpful where a site is part of a wider portfolio within a company or where the generator is owned by multiple entities, allowing flexibility in their asset design without surplus options adding premia to risk calculations. Ringfencing trades or hedges to each individual site participating in the mechanism would increase certainty about scheme return. While operators may need to participate in new markets in order to gain similar revenues, they are likely to be able to adapt their models, allowing for the continuation of Strike Price forecasting.	Neutral impact
Impacts on consumers	The cap and floor would need to be set at levels that reduce risk for investors, but still retain genuine value for money for consumers. Cost of capital reductions should be reflected in prices, recognising the lower risk for investors. Further work to understand the pricing approach may be needed to gain a full understanding of consumer impacts against the current CfD counterfactual. Consumers would only make payments – via suppliers - if generators failed to meet their revenue floor. While this is possible, the allocation process should minimise this risk in order to encourage activities which see revenues exceeding the minimum level.	Neutral impact

Impacts on generators	With a design based on revenue streams across multiple markets, more generators who are able to behave flexibly could participate. This could drive down the revenues that would be available to the wider generation group, but the increase in scale of the overall generation requirements more than offset this effect. While the approach is more complex than the current model, generators would likely be able to adapt relatively easily.	Net neutral
Other considerations	Longer term liquidity should improve as generators would no longer be reliant on the day ahead price for their revenues. Exposure to market signals would be increased significantly, with the design encouraging turn down in certain situations such as low market prices. De-coupling payments from output potentially allows more downtime and maintenance, synchronised with system needs. This should help to extend the lifetime of the asset. However, this is limited if the generator has exceeded the cap.	Mixed, overall positive

A consultation will help gauge stakeholder perspectives and concerns about the proposed changes to the CfD scheme and difference payments being based on a cap and floor methodology incorporating multiple revenue streams.

- The number of negative pricing periods are expected to increase in future. Would a CfD scheme that achieves a lower strike price equivalent, but with less volume uncertainty, be appealing to investors, assuming operators can engage in alternative markets for additional revenue?
- To what extent would the cap and floor mechanism help mitigate the negative impact of volume surplus supply? Would it deliver a more nuanced market response where operators are less reliant on maximising periods of generation for reliable revenue streams?
- How might the complexity involved in determining cap and floor levels affect the appetite for investment? Could sufficiently clear scheme rules provide enough clarity for developers to model?
- Would additional administrative complexity associated with a cap and floor act as an absolute deterrent to engagement with the scheme? Would this be materially different if a floating or “soft” cap were to apply?
- What ancillary service and additional revenue streams should be eligible under this scheme? What additional changes would be required to ensure activity by CfD supported assets didn’t adversely impact corresponding markets having an overall negative system impact?

6.3 Overall assessment of case studies

Both the deemed output CfD and revenue cap and floor would incentivise more flexible behaviour from generators, helping to address the major issue of output being maximised where this is not beneficial to the system. Both options have the potential to improve on the proven CfD, scoring well across a range of key measures set out in REMA, supporting achieving net zero by 2035.

REMA Assessment Criteria	Description	Deemed output CfD compatibility	Revenue cap and floor CfD compatibility
Least cost	Market design solutions should offer best value for the consumer and reflect long term whole system costs and benefits		
Deliverability	Changes must be feasible within specified timescales and aim to cause the least amount of disruption possible throughout the transition, taking into account the highly complex and integrated nature of the power system.		
Investor confidence	Investor confidence needs to be maintained and built, and investment risks should be borne by those best able to manage it.		
Whole system flexibility	Where it is efficient to do so, market design should encourage market participants to act flexibly.		
Adaptability	Market design should be adaptive, responsive to change, resilient to uncertainty, such as where commodity prices fluctuate or new system requirements emerge.		

The success of the CfD schemes has seen widespread trust in the current arrangements. Even where the scheme evolves between Allocation Rounds, investor interest has been stable. The European Commission is seeking to expand the use of CfDs in their members' energy markets, recognising the suitability of CfDs for funding new investment in low carbon generation in a way that reduces risk for consumers and ensures value for money.

- The revenue cap and floor may be more attractive for low risk appetite investors, as it would provide significant levels of certainty for minimum revenues, reducing volume risk, alongside the price risk benefits of the existing scheme.

- The deemed output CfD offers some advantages over the cap and floor for investors seeking more opportunities to optimise their revenue stream and be more active in other markets.

We therefore recommend that both options be considered as viable options for reform. If combined with other reforms – such as TNUoS – they both have the potential to deliver the improvements necessary for future reform.

6.4 Implementing Mass Low Carbon Options

Illustrating the CfD's capacity for ongoing evolution in response to a changing market, the Government recently consulted on the future of the CfD for Allocation Round Six and beyond (closed February 2023) and called for evidence about the non price factors affecting the auction process "in recognition of the deployment challenges currently faced by the renewable energy industry" (close May 2023).

CfDs were introduced via the Energy Act 2013. Powers of amendment were granted to the Secretary of State, and subsequently more than ten Statutory Instruments relating to CfDs have been laid before parliament. If the CfD scheme was redesigned, changes to the core legal documents would be required. Changes to CfD Contracts are effectively changes to private legal contracts and have been successfully incorporated in the time between Allocation Rounds (1 or 2 years).

- CfD agreement: Standard CFD Agreement, Unincorporated JV CFD, Private Network CFD, Offshore Wind options (Phased Single Metering, CFD Phased Apportioned Metering CFD)
- CfD terms and conditions

Eligibility requirements for the deemed and cap and floor options are expected to remain largely consistent with the current CfD approach. As a result substantial reform would not be expected for the supply chain declaration, the Balancing and Settlement Code, or the Transmission, Generation or Supplier Licence Conditions.

The Grid Code would be revised to the extent required for the respective system operator to respond to the amended availability of assets, although this impact is expected to be modest in the context of parallel electricity system reforms. Some ancillary service or market access rules and guidance may need to be amended so generation assets with a CfD are no longer prohibited from participation.

In the case of the deemed variant, time would need to be taken to design suitable controls, to ensure investors could be confident of predictable ranges of return, and to minimise the risk of perceived gaming of the process to the detriment of the overall system. Oversight by an independent administrative body, and clearly defined contractual tolerances would ensure confidence was maintained. Transparency around outcomes in a range of market conditions and for different technology types will help existing investors understand the changes to volume risk in relation to the existing CfD.

The cap and floor model would benefit from engagement with experienced investors and sense checking the time it would take to adapt their forecasting models, and their approach to auctions. Anecdotally, this amendment would be possible with sufficient lead time, but a range of investor types and technology backers should have their opinions sought to ensure there are no unintended consequences or shrinking of the market.

Transparency must be maintained throughout any transition period to maintain the confidence of renewable generation operators and attract new investments. The Climate Change Committee estimated that investment in the power sector must reach £50 billion a year by 2030. Groups such as Energy UK have encouraged policymakers to ensure that any policy which would bring about wholesale change to the market at a time in which the power sector requires significant investment, is carried out through a rigorous and highly transparent analytical process with clear consideration being given to the impact of uncertainty.

Previous changes to the CfD scheme have resulted in a legal challenge, which could negatively affect confidence in the overall scheme or delay deployment of any changes along with any benefits. Consequential impacts of any scheme introduced under REMA would need to be assessed before deployment. In response to the energy price crisis the Government introduced the Energy Generator Levy (EGL), placing a tax on “exceptional” electricity generation receipts of qualifying generating undertakings from 1 January 2023 to 31 March 2028. Although CfD scheme generation sold at an agreed Strike Price is excluded, power sold via merchant markets is not and this calculation may form part of the business case.

7. Conclusions & roadmap for delivery

In REMA the government has committed to a comprehensive review of electricity market design to ensure its suitability for maintaining energy security and affordability as the electricity sector transitions to a low-carbon future. Effective and properly structured markets are essential to decarbonising power by 2035, and achieving net zero across the whole economy by 2050.

This report identifies two evolutionary reform options that correspond with the overall aims of REMA. The deemed output CfD and revenue cap and floor CfD variants could incentivise more flexible behaviour from generators. These options would support net zero ambitions by maintaining GB's attractiveness to investors while improving overall system benefits alongside other complementary reforms.

The evolution of the CfD model can build on investor familiarity with structure, mechanics, and potential returns. International adoption of CfDs would increase the pool of potential investors who find the CfD appealing, being able to assess investment opportunities in different projects and markets. Investors would need to be engaged throughout any adjustment period to maintain confidence, which could avoid the disruption of introducing an entirely new energy system, or one unproven in a territory such as GB. The revenue cap and floor may be more attractive for low risk appetite investors, as it would provide significant levels of certainty for minimum revenues, reducing volume risk, alongside the price risk benefits of the existing scheme. The deemed output CfD offers some advantages over the cap and floor for investors seeking more opportunities to optimise their revenue stream.

We recommend that both options be considered viable pathways for reform, combined with other granular reform options. Widespread concerns about attracting investment to low carbon generation could be allayed by the swift implementation of change – following adequate assessment.

The more radical options presented in REMA, such as the introduction of LMP, present a significant risk to the delivery of 2035 and 2050 net zero deadlines – LMP could take more than ten years to implement, and even longer to deliver benefits. LMP has never been implemented in a market as complex as GB, and investor discomfort would likely add to capital costs, ultimately driving up consumer prices and wiping out potential benefits. Attempting the introduction of a split market would see the GB electricity market operate as an experiment. Benefits are uncertain, and substantial concerns about liquidity and investor attractiveness remain.

7.1 Delivery timetables

The maximum pace of change must be understood as part of any benefits case. Incorporating realistic delivery timetables will be critical in assessing the ability of any option to impact the 2035 and 2050 net zero timescales.

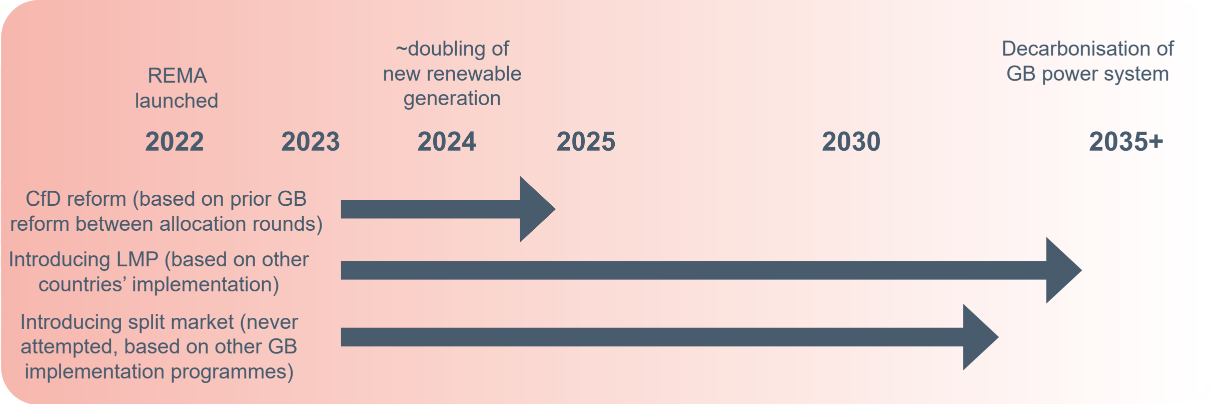
Investor confidence depends on certainty. The risk of an investor hiatus in GB is particularly acute due to the acceleration of international competition for funding, skills and equipment. Prolonged uncertainty, and a long design phase, could see funders with international positions may be attracted to alternative schemes ready to offer secure returns. For example, the US's Inflation Reduction Act and accompanying package seeks to promote economic growth while enhancing energy security by encouraging the relocation of manufacturing and supply chains to the US and neighbouring countries. The 2022 package commits $470bn in climate-related investments over the next decade and is designed to prompt a further $1trn of private investment. European countries have identified the IRA as a potential threat to their industrial and climate ambitions, competing for capital and jobs. European funding will draw from REPowerEU and the Recovery and Resilience Plan funding and may be in excess of €470bn. Countries may have access to additional funding, for example Germany and the Climate and Transformation Fund worth around €180bn.

Previous energy industry transformation programmes have experienced overruns and under delivery, in GB and internationally. Less ambitious reform than the revolutionary options of REMA experienced delivery challenges in less complex market conditions than present in GB in 2023.

- 11 years – Project Nexus reformed the gas industry's central IT systems, from distribution price control to implementation
- 6 years – P272 saw the introduction of half-hourly settlement for a subset of business customers, from modification raise to implementation, with market wide half hourly settlement currently undergoing delays
- 3 years – New Electricity Trading Arrangements (NETA), was primarily an IT change during a period with fewer market participants
- Outside the GB market, the implementation of an Integrated Single Electricity Market in the Irish market took around 4 and a half years from the initial design consultation to go-live, with substantially fewer market participants

By examining previous projects, insights can be gained to inform the development of a feasible timetable. This helps visualise the potential time required for the program and milestones associated with net zero timescales.

Figure 12: Projected timelines for delivery based upon prior programmes of reform



Source: Cornwall Insight

7.2 Topics for the Autumn 2023 consultation

As the REMA process continues, there are a number of areas that are recommended for inclusion in further stakeholder engagement and consultation. These include:

- **Roadmap and timelines.** Development of credible delivery pathways for the options are essential to assess potential benefits against implementation risks. Inclusion of an indicative timescale, and the timing and duration of any transition period, for each option presented in the Autumn 2023 Consultation would allow for stakeholder comments. Comments should be encouraged on the three relevant phases of change.
    - Development requirements – any consequential consultations, central systems change requirements, stakeholder systems and process changes, legislative requirements
    - Implementation date – when would the option come into effect?
    - Time to impact on net zero goals – the option may be live substantially before the effect on decarbonisation targets is felt. To what extent will this be dependent on behavioural change, or subject to conditional market confidence?
- **Option interactions.** With many options on the table that are likely to be considered together as a package, it is recommended that the interactions of options are fully considered. Analysis should consider impacts of standalone options, as well as how options would work in combination with others.
- **Interim transition risks**. Our December 2022 Renewables Pipeline Tracker indicates that there is a renewables pipeline (scoping through to under construction) of over 215GW assets. How much of this is at risk of being paused, or abandoned under any option? What is the impact of delayed asset deployment on overall net zero targets, as well as weakened supply chains?

- **Cost of capital risks**. Cost benefit analysis of each option should reflect the more volatile macroeconomic outlook of today, rather than the relatively benign financial situation of the last decade. What cost of capital uplift are investors and developers expecting to see compared to historical norms?
- **Grandfathering**. To the extent this is possible, for each option explain what will happen to existing contractual agreements e.g. existing CfDs, CfD allocation rounds prior to the option being implemented, existing Power Purchase Agreements (corporate and utility types, <3 year, 3-15 year, >15 year), if the change will be enacted by a change in law triggering relevant contractual clauses.
- **Unintended consequences**. How might a cynical actor act to defeat the programme's aims for their own benefit? For example, by opening projects to increased revenue stream options, it could be possible to receive multiple bill-payer backed support subsidies. Those schemes intended to meet a near term system need may have conflicting incentives to those addressing long term strategic aims.
- **Evolutionary benefits avoiding revolutionary disruption.** If consequential changes are necessary to facilitate a revolutionary option, benefits are attributable to the evolutionary consequential changes? The efficacy of those additional measures should be assessed to see if they could sufficiently facilitate REMA's aims without the disruption and delays LMP could cause.

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