REMA INSIGHT PAPER

Progressive Market Reform for a Clean Power System

An agenda for an efficient GB electricity market that increases low-carbon investment and delivers consumer value.

July 2024

About Regen

Regen is an independent centre of energy expertise with a mission to accelerate the transition to a zero-carbon energy system. We have nearly 20 years' experience in transforming the energy system for net zero and delivering expert advice and market insight on the systemic challenges of decarbonising power, heat, and transport.

Regen is also a membership organisation, with a wide range of members who share our mission from across the energy sector including clean energy developers, networks companies, energy users, local authorities, community energy groups, academic institutions, and research organisations. Regen also manages the Electricity Storage Network (ESN) – the voice of the UK storage industry.

Acknowledgements

We would like to express our sincere appreciation to all those who contributed to the successful completion of this report. While this paper is the work of Regen, the **progressive market reform** agenda is a compendium of ideas that draws heavily on discussions with a wide range of industry stakeholders at numerous webinars, events and REMA workshops as well as bilateral meetings.

A special thanks to Regen associates **Dr Simon Gill** and **Gareth Miller**, for their review and contributions.

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	This report is a position paper. It sets out Regen's current thinking on the subject of market reform and provides a high-level summary of policy options.

About this paper

Background

As a new Labour government takes office, with a new clean power mission, the Review of Electricity Market Arrangements (REMA) has been running for over two years. This could herald a major programme of reform for the GB electricity markets and investment support schemes. It is critical, however, that market reform is aligned with the overarching goal to decarbonise the UK power system, which will then provide a low-carbon energy source for heating, transport and industrial uses.

Purpose

This paper aims to provide the incoming government, REMA team and wider industry stakeholders with a comprehensive set of reform options based on the retention of an enhanced national wholesale market. This accelerated reform agenda includes liberalised trading arrangements that embrace the potential opportunities of a smarter, more flexible and highly digitalised energy system, improving market and operational efficiency and delivering a clean power system.

Key messages

The paper argues that the current wholesale market model is not fundamentally broken and that radical reform options, including nodal or zonal pricing, will not deliver the benefits claimed, but would instead increase both investment risk and consumer costs. As an alternative, adoption of a **progressive market reform** agenda can deliver more certain benefits, while accelerating investment in low-carbon solutions and ensuring that the energy transition provides wider value for consumers, communities, economy and society.

It further argues that, while system operation with high renewables will require new market solutions and greater capability within the National Energy System Operator (NESO), there should be no conflict between an agile trading market and efficient system operation.

Progressive market reform

The progressive market reform agenda is framed within an overarching strategic and spatial energy plan at a national and regional/local level. It is based on greater use of low-carbon flexibility and efficient system operations enabled by: enhanced balancing and flexibility markets; wider market access; improved forecasting and information visibility; and the digitalisation and automation of market processes, system dispatch and control room functions. Interconnection efficiency will require a greater level of cross-border coordination, with stronger process and planning integration between GB and neighbouring EU markets.

Key recommendations

The report makes a number of recommendations, which are listed in the Executive summary and within the reform agenda. The three key recommendations for a new government are to:

1. **Adopt a programme of progressive market reform** based on the building blocks of the national market, with liberalised trading, decentralised dispatch and redispatch via an enhanced Balancing Mechanism, constraint and flexibility markets.
2. **Drop zonal pricing as a market option.** The benefit assessment that has already been made by the Department for Energy Security and Net Zero and the responses to the second REMA consultation should provide sufficient evidence that zonal pricing is not the answer.
3. **Restate the REMA objectives** with a broader remit to address wider socio-economic and consumer benefits, a stronger steer to support the government's ambition to accelerate net zero investment to deliver a clean power system, and support for local energy supply and regional energy and economic strategies.

Contents

Executive summary

The Review of Electricity Market Arrangements (REMA) has stimulated a vigorous debate around whether the GB electricity market is fundamentally broken and requires a radical redesign, or whether the current trading arrangements could, with **significant reform**, provide a market that would accelerate low-carbon investment, incentivise greater use of flexibility to provide resilience, support efficient system operation and deliver consumer value.

Regen's view is that a programme of **progressive market reform**, based on a national market model with decentralised dispatch and bilateral trading, can provide a smart and flexible solution to meet the REMA market design objectives and accelerate investment to deliver the new government's clean power mission. This view is shared by the majority of industry stakeholders.[1] Regen also considers that ensuring a just energy transition that empowers both the consumer and communities, and delivers wider benefits to society, should be a market reform objective.

This view has been informed by two key conclusions drawn from Regen's own research, engagement with the REMA process and analysis of the consultation documents:

1. **That the benefits claimed for radical options, such as Locational Marginal Pricing (LMP), have been overstated, while the costs have been underestimated or omitted from the analysis.** The implementation and investment risks associated with a market redesign would seriously impact the progress towards the new government's clean power goals, reduce investment and economic growth, reduce market liquidity and, ultimately, increase consumer costs.
2. **That the current market arrangements are not fundamentally broken, but possess the potential to provide GB with a sophisticated and competitive energy market.** The market requires enhancement, investment and modernisation, but the building blocks of a liberalised trading market and the hybrid decentralised wholesale market dispatch with a centralised redispatch – via an enhanced Balancing Mechanism (BM) and flexibility markets – is still fit for purpose and, combined with appropriate investment support schemes, can form the basis of a net zero energy market.

Regen's response welcomed the publication of the second REMA consultation, including the decision to drop the most disruptive market reforms options: a *split market*, which would have attempted to create a separate market for variable renewables, and the option to reconfigure the GB market into a *nodal market with LMP*.

While the decision to drop these options has been welcomed by most industry stakeholders, zonal pricing has been retained as a potential option. The zonal pricing model has not been

[1] Responses to the first REMA consultation published by DESNZ showed that 75% of respondents supported exploration of incremental reforms – a higher level of support compared to nodal or zonal LMP.

defined in any detail and could be more or less radical depending on the design options taken. It is, therefore, difficult to critique. However, whatever the specifics of the design, zonal pricing will significantly reduce the ability of the private sector to invest in renewables generation in areas where they are most suitable.

Regen's recommendation is that **the incoming government should drop zonal pricing** so that resources and time can be focused on the development of the energy strategy, implementation of alternative progressive reform options and the urgent task of securing low-carbon investment.

Regen supports many of the reform proposals within the second REMA consultation. However, in all areas, more detailed design and further consultation is needed. The recognition by DESNZ that a realistic and holistic counterfactual should be developed in order to fully explore the merits of retaining the current national market structure is positive. Developing the national market option as an integrated programme should now be the priority.

This paper argues that, while system operation with high renewables will require more advanced tools, new market solutions and greater capability within the National Energy System Operator (NESO), there should be no conflict of objective or outcome between the creation of an agile and dynamic trading market and efficient system operation. In fact, to achieve a net zero energy future, **energy strategy, markets, investment framework and system operation must be developed together**.

Principles of progressive market reform

The principles underpinning the progressive market reform agenda are that reform must:

- Respond to the urgency of the UK energy transition and the new government's clean power mission, recognising the benefits that decarbonisation will bring to consumers, wider society, industry and economy.
- Aim to both create an agile and dynamic market and enable efficient system operation.
- Avoid creating a hiatus in the energy transition by balancing the need to make impactful change with the need to maintain momentum within existing reform programmes and investor confidence in the wider market.
- Recognise the reality that market reforms will be difficult to implement at a time when the energy sector is in full-blown transition, and can only be achieved with broad support from across the industry, investors and consumer stakeholders.
- Ensure that wholesale market reform is considered in the wider context of allied reforms in retail markets, strategic planning, cross-border integration, consumer protection, grid investment and network charging.
- Support the principle that risk is best placed where it can be managed.
- Ensure that locational signals and markets are aligned with, and do not undermine, the overall Strategic Spatial Energy Plan.

- Embrace the opportunities provided by open data, digitalisation, IT integration, automation and AI to enhance markets and system operations.
- Place due emphasis on fairness, based on the principle that the consumer should be enabled to become an active participant in the energy market, but should not be unfairly exploited to fix system issues, or exposed to energy system price signals to which they may be unable to respond.
- Recognise that the GB electricity market is not fundamentally broken and provides successful principles of a national electricity market, with a rich ecosystem of bilateral trading, but needs significant enhancement to work efficiently in a high renewable generation context.

Critique of the current market arrangements

The perceived and real trade-off between a liberalised wholesale trading market and efficient system operation is discussed in the introduction of this paper, which outlines market reform and provides a short critical analysis of the current market arrangements.

The analysis shows that there are indeed issues within the current market and system operation arrangements, including: a lack of market visibility for the system operator; limitations within the balancing and control room functions; sub-optimal performance of interconnectors; barriers to flexibility; misaligned (but not necessarily weak) locational signals for investment; market distortion related to revenue support schemes and examples of imperfect market competition and gaming. There is also a critical lack of an overall net zero strategy and delivery plan which, more than anything else, is undermining investment and market efficiency while driving up constraint and system costs for the consumer.

The analysis also recognises that, since the liberalisation of the market following the New Electricity Market Arrangements (NETA) reforms in 2001 and the 2012 Electricity Market Reform (EMR) support schemes, the GB market has delivered a very significant increase in renewable energy and electricity storage deployment, both large and small scale. One of the key strengths of the current wholesale trading arrangements is that there are many more routes to market, including the use of long-term Power Purchase Agreement contracts, which have been essential for new generation projects.

The paper's conclusion is that, while there are significant issues and identified points of weakness within the current market arrangements, especially around interconnectors, the overall market design is not fundamentally broken. It requires enhancement, investment and innovation, but the foundation of a liberalised trading market, with a hybrid decentralised wholesale market self-dispatch and central re-dispatch for final balancing/operability, is still fit for purpose and, combined with appropriate investment support schemes, can form the basis to attract investment and create a world-leading net zero energy market.

Rather than corral or curtail the market, **the goal of progressive market reform should be to combine the strengths of a liberalised wholesale energy trading market with smart flexibility solutions and highly digitalised system operations**.

An agenda for progressive market reform

The main body of this paper sets out how a package of reforms could be brought together into an integrated programme of change within the current GB market arrangements. The core objectives for the progressive market reform agenda are based on the four REMA market reform challenges set out in the second consultation, with the addition of an overarching objective to deliver a net zero energy system and the extension of the consumer value objective to include more progressive themes around a just transition, fuel poverty and local energy supply, which will be of high priority for consumers and an incoming government.

The advantage of a progressive approach is that it would build on the strengths of the existing GB bilateral trading arrangements and revenue support models, with reforms that could be implemented more quickly, and with less implementation and investment risk, than would be associated with more radical reform options. Progressive reforms also have low-regret costs since, in many instances, such reforms would be required in any future market.

This is not to say that a progressive market reform agenda would be easy or trivial to implement. The agenda of reforms, innovation and policy interventions identified in this paper would constitute a major programme of work that would modernise and transform the GB electricity market. Rapid implementation alongside wider reforms such as national and regional strategic planning, grid investment, grid access and connections, network charging, digitalisation of system operations and retail market reform will be a major challenge, especially at a time of significant change across the energy system and creation of a new NESO.

The energy transition will fail if it doesn't engage with and empower consumers, and address the issues around fuel poverty and energy justice and secure wider economic and societal benefits. **The scope of the progressive market reform agenda goes beyond that of the REMA consultation challenges** to draw in important elements of the energy transition: local energy devolution, consumer empowerment, fuel poverty action, local energy supply and securing wider economic and societal benefits for UK communities.

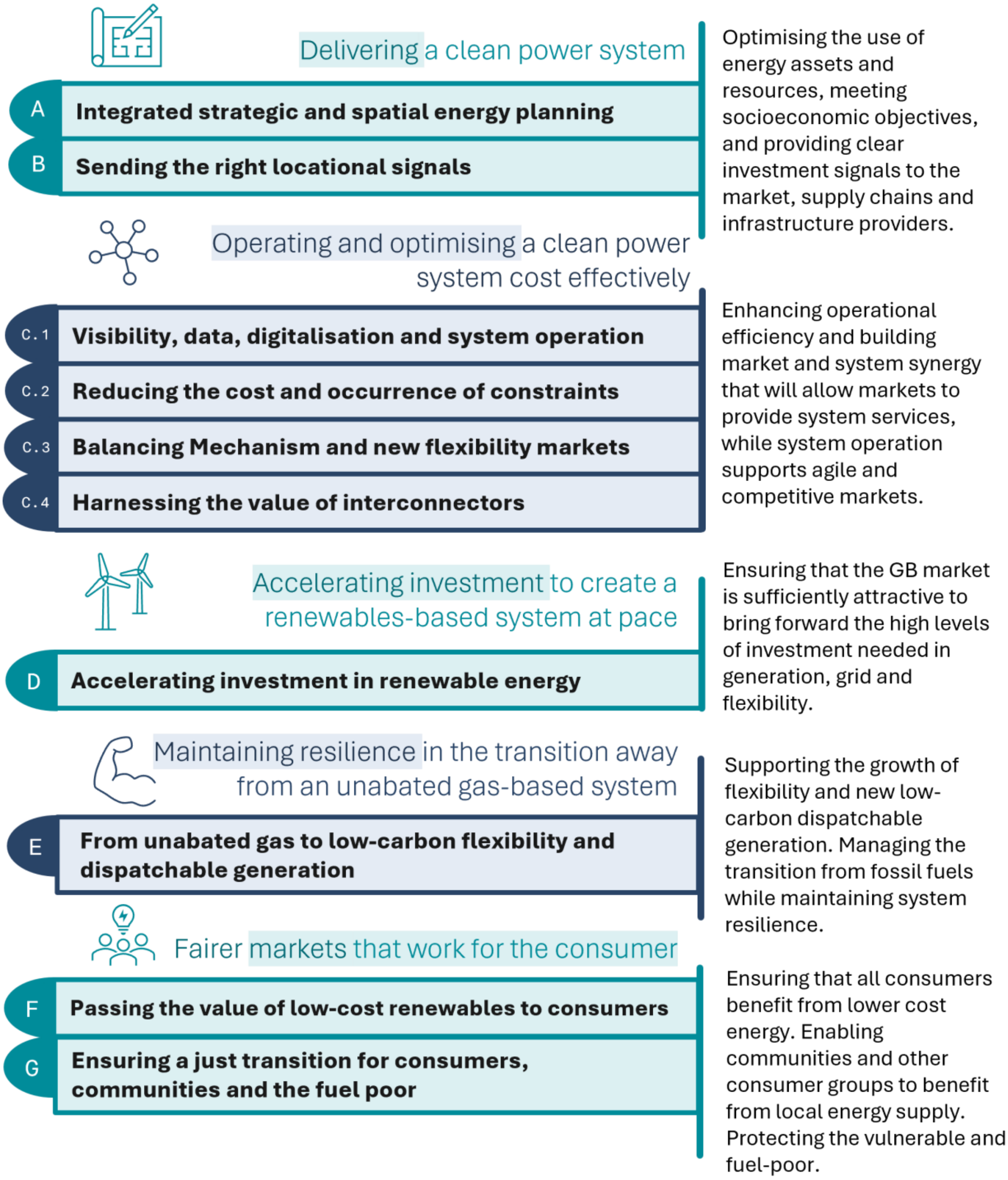

Figure 1. An outline of the progressive market reform agenda, broken down into themes A to G, which are set out in the second part of this paper.

Strategic spatial energy planning to underpin locational signals

A critical area of reform, which also has almost universal stakeholder backing, currently sits outside the main scope of REMA. The UK needs an integrated, whole-system Strategic Spatial Energy Plan (SSEP) at both a national and regional level. The scope of the plan should go beyond the electricity system to cover all aspects of energy: the decarbonisation of heat and transport, integration with industrial strategy and industrial decarbonisation, and development of hydrogen (and carbon capture and storage) infrastructure. Within the electricity system, it should cover generation and storage technologies, grid infrastructure and interconnectors.

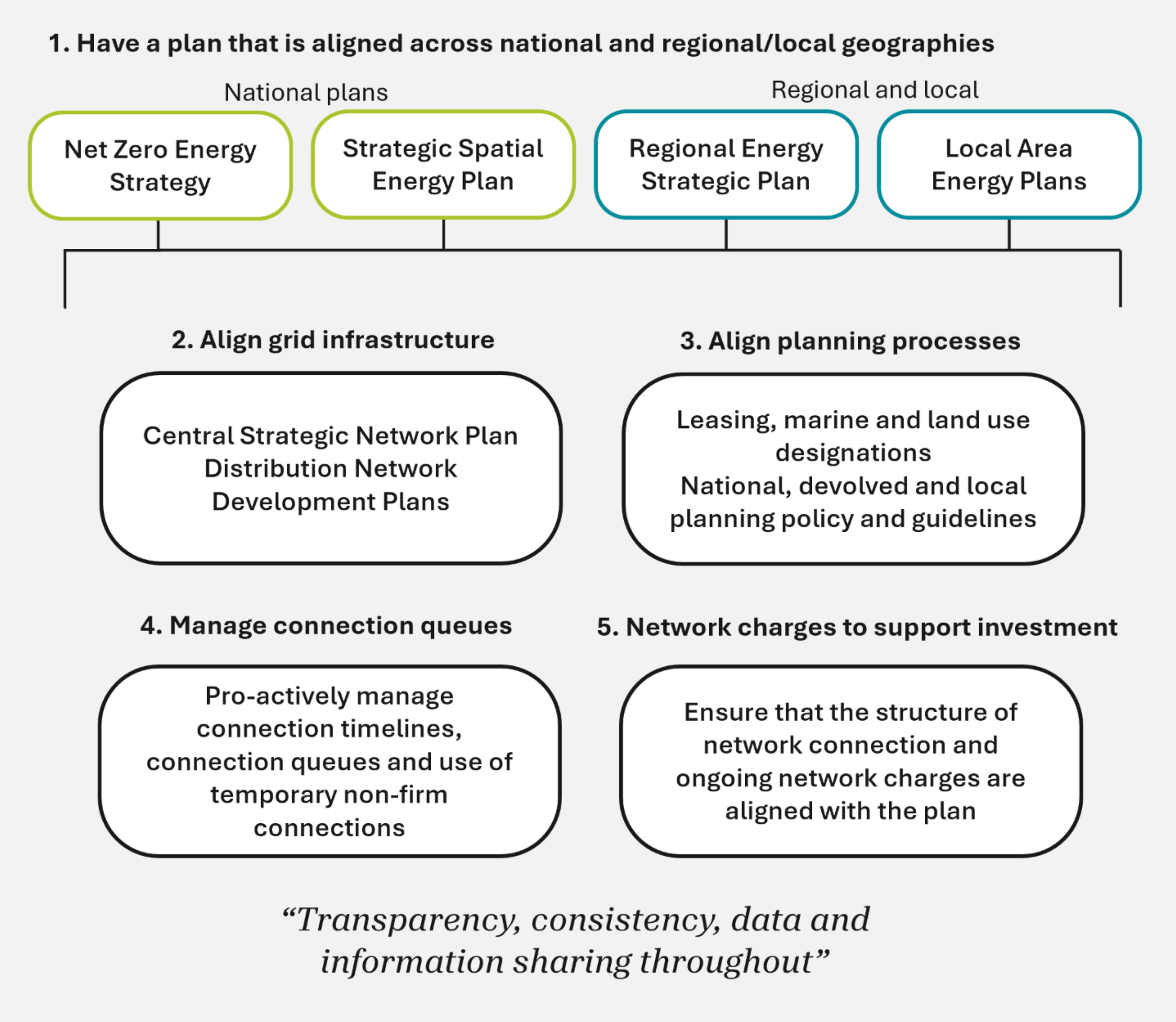

Figure 2. The plan should inform and dictate locational signals through infrastructure, planning, connections and network charges

Energy plans should be set at an appropriate level of detail to provide a framework to enable market investment. It should inform, and in some areas dictate, infrastructure investment, planning, connection queue management and network charging. Energy plans must be allied with national and regional plans for economic developments, supply chains and skills.

The existence of an overarching plan has implications for market reform. The development of whole-system energy plans that are supported by national and regional stakeholders, have weight within planning, land use and lease awards, and lead to accelerated network investment would go a long way to providing the locational investment signals that have been missing, as well as speeding up planning decisions and adding to investor confidence.

For large projects (nuclear and offshore wind) the location would in practice set by the strategic plan. The challenge of sending locational signals for investment in other technologies would then be much more manageable, through a combination of connection queue management, connection charging and reformed network charging.

A key principle of progressive market reform is that both financial and non-financial locational signals are aligned with the delivery of the overall SSEP.

Accelerating investment and reducing risk

The incoming government has set out ambitious manifesto goals to rapidly increase renewable energy capacity as well as drive investment grid infrastructure and other net zero technologies such as energy storage, new nuclear, hydrogen and carbon capture. This investment will predominantly come from the private sector, aided by government-backed revenue support schemes and targeted public investment.

The revenue support schemes (including the CfD and the CM) are largely in place, although there is scope for reform and enhancement of these schemes as part of the progressive market reform agenda, as outlined in Theme D and Theme E of this paper.

However, to achieve the level of investment needed at a cost that is acceptable, it's critical that the UK remains an attractive market for investment. High up on any investor's risk assessment will be the risk of regulatory and market policy changes. All market reforms will carry some risk, and investors have demonstrated an ability to absorb policy risk as the energy market has adapted and evolved during the transition thus far, particularly where the outcome of change on their projected investment returns can be confidently quantified. However, if investors are unable to 'price in' the risk that market reforms will create for their future revenue streams, they will face challenges in terms of both cost of capital and access to finance. It is then likely that further intervention will be required to mitigate against that uncertainty and to maintain investment flows. For example, the introduction of Final Investment Decision Enabling for Renewables (FIDER) contracts, to bridge the gap between the announced closure of the Renewables Obligation and investor familiarity with the detailed design of the new CfD, was required specifically to maintain investment momentum during the implementation phase of EMR.

Investment risk is often assessed as a change in the cost of capital that will manifest once reforms are implemented in a settled market, and indeed increased finance costs are a key driver of overall project costs and cost of energy. However, cost of capital is just one of several risk outcomes. Risk will evolve during the policy process. During the transition phase, when policy is being designed, implemented and new markets established, investors will have lower confidence in projected returns for their investments than during the enduring phase that follows, once markets have adjusted to the change and have a track record of performance.

The length of the transition phase, allied to the complexity of forecasting impacts, will therefore have a material impact on the flow and cost of investment. The longer the transition phase, and the more complex the change, the greater the risk of negative impact on flow of capital, and increased costs of capital. That, in turn, would reduce the volume of viable projects to attract the supply chain of construction and service contractors, making the UK a less attractive destination for their activities. This demonstrates that the appreciation of impacts of policy change on investment cannot simply be reduced to movements in costs of capital, but requires an assessment of the degree to which the change could drive a hiatus in investment, or disrupt project pipelines and supply chains, and what this means for the likelihood of achieving broader policy objectives.

GB policymakers also need to be aware of competition from other markets, including European energy markets that are now proceeding with reforms at a more rapid pace.

The challenge for policymakers is to strike the right balance between the need for market reforms, which will reduce costs and bring wider benefits, and the inherent risk that change brings to the investment community. To do this, policymakers need a more sophisticated and comprehensive framework in order to assess the impact of policy change.

In the context of REMA, it's clear that radical reform options requiring years of implementation, leading to an uncertain outcome that is impossible for investors to quantify, will have a far greater risk factor and negative impact for investment. A progressive market reform programme will still need to carefully assess investment risk, but reforms that are evolutionary and based on underlying market arrangements that work are far less likely to incur an investment hiatus. This is because the projected outcome of change in investor models can be pegged to a benchmark cost or benefit present in the status quo arrangement in the current markets. For more radical reform options, no such benchmarks would exist.

Busting the dichotomy between system and market efficiency

The liberalisation of the wholesale market arrangements that occurred after the NETA reforms in 2001 has brought many advantages to the GB market, enabling bilateral trading and decentralised dispatch and balancing, and helping to support the growth of renewable energy, both large and small scale.

The trade-off, however, has been some loss of operational control and efficiency. The view, however, that the market is therefore broken, and can only be fixed by a return to central dispatch and a marginal price algorithm, is incorrect. Our analysis identifies that there are many ways in which both system and market efficiency can be achieved – by, for example, enhancing visibility and control room functions, baring down on constraint costs, creating new markets for flexibility, enhancing the BM and fixing the various problems associated with the operation of interconnectors.

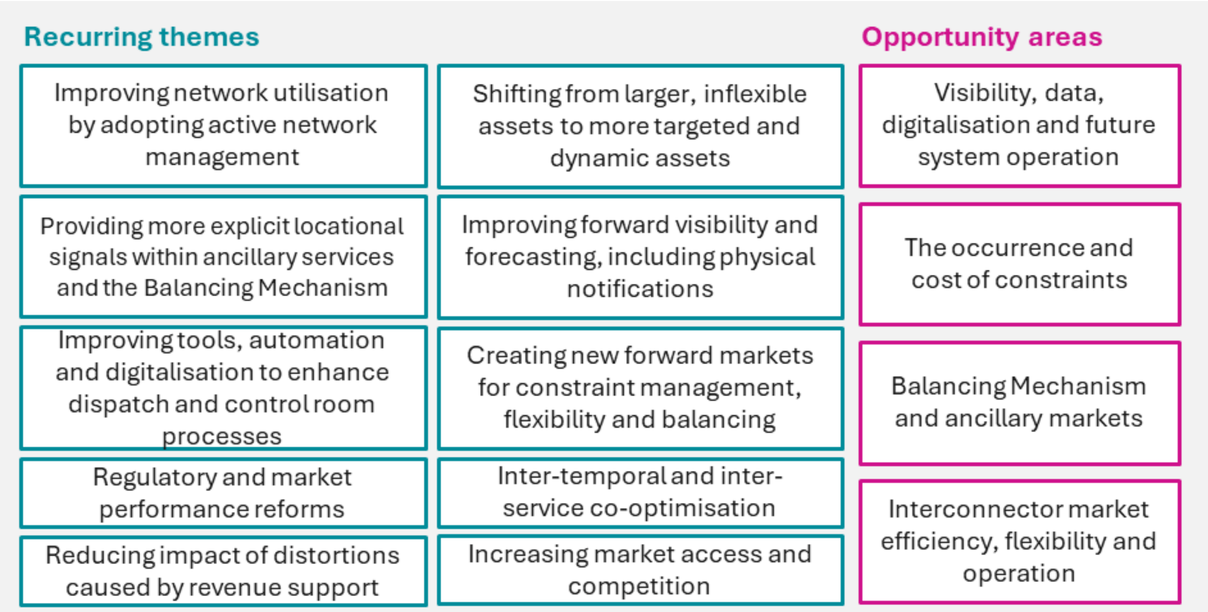

Figure 3. Operational efficiency is a key challenge and opportunity area for enhancement, innovation and reform

Markets that work for consumers, communities and society

The progressive market reform agenda has taken a wider view of consumer value, focusing not just on the lowest-cost pathway to decarbonisation (which is an important consideration) but also on a wider value proposition that includes:

- Boosting local energy supply and enabling consumers to buy energy produced locally at a fair price
- Addressing the unfairness and inconsistency produced by current levy arrangements
- Enabling a future government, or potentially devolved and local governments, to establish a social tariff to address fuel poverty or other targeted consumers
- Supporting the development of community-owned energy
- Aligning the value of low-carbon energy with other socio-economic goals, including regional economic development, industrial strategy, skills, employment and growth.

High-level recommendations

We recommend that the incoming UK government, working with Ofgem, the NESO, devolved administrations, the industry and stakeholders, should **develop a more holistic and integrated programme of reform** under the banner of the clean power mission.

REMA should continue as a coordinated programme of reform, but needs to be given a **broader remit and perspective on electricity market reform**, grounded in our social and economic needs, and focused on delivering the clean power mission as a foundation for a wider net zero energy system.

Specifically, Regen is recommending that the incoming government should:

1. **Adopt a programme of progressive market reform** based on the building blocks of the national market with liberalised trading, decentralised dispatch and redispatch via an enhanced BM and new constraint and flexibility markets.
2. **Drop zonal pricing as a market option.** The benefit assessment that has already been made by DESNZ and the responses to the second REMA consultation should provide sufficient evidence that zonal pricing is not the answer.
3. **Restate the REMA objectives,** with a broader remit to address wider socio-economic benefits and deliver the strategic energy plan, a stronger steer to support the government's accelerated ambition for clean power, net zero investment and economic growth, and support for local energy supply and community energy.
4. **Establish an overarching governance and engagement model for REMA**, with a broader governance board including industry and consumer stakeholders.
5. **Carry forward the in-progress proposals to develop a Strategic Spatial Energy Plan (SSEP) and the establishment of Regional Energy Strategic Planners (RESPs)**, with an aim to publish the terms of reference for the SSEP within the first 100 days and to have the first SSEP complete by the end of 2025.
6. **Establish a taskforce to address the issues around interconnectors,** with a focus on implementing an overall interconnector strategic plan, establishing a closer alignment with EU markets and to improve the efficient operation of interconnectors, including the ability of the NESO to manage interconnector flows for flexibility and balancing.
7. **Task the NESO to present a plan to improve system operation, control room functions and constraint management** by investing in digitalisation, automation, forecasting tools, increasing visibility and new market development.

Further recommendations for a progressive market reform agenda are outlined from Themes A - E in this paper.

Introduction to market reform and current market arrangements

The Review of Electricity Market Arrangements, launched by the UK government in the summer of 2022, could potentially bring forward the most comprehensive and far-reaching set of reforms to the UK electricity market since the NETA and BETTA[2] reforms at the turn of the century.

> "Our core objective for the REMA programme is to **reform** our electricity market arrangements so that they facilitate the **full decarbonisation** of the electricity system **by 2035**, subject to **security of supply**, and are **cost effective** for consumers." – **BEIS (now DESNZ), July 2022**

The scope of REMA focuses on the structure and operation of the GB electricity wholesale market, but also includes a review of support mechanisms, capacity adequacy, flexibility/balancing and system operability. It could also significantly impact on the future of GB retail markets and investment in infrastructure and networks.

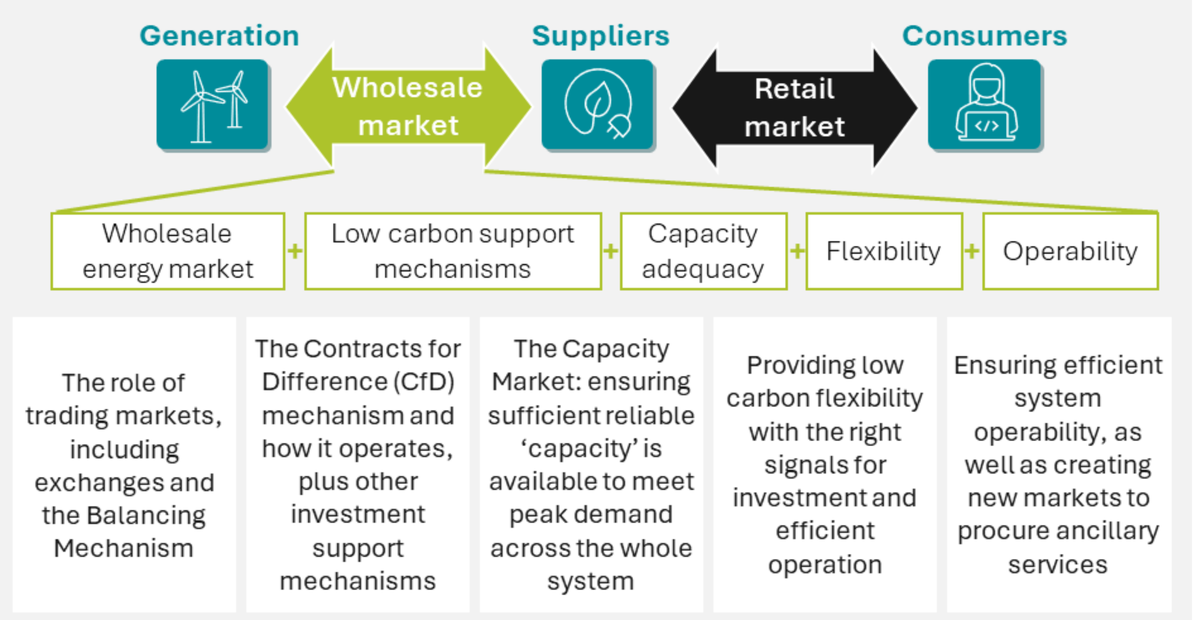

Figure 4. REMA outline scope of reform in the first REMA consultation. Source: Regen

[2] New Electricity Trading Arrangements (NETA) 2001, British Electricity Trading and Transmission Arrangements (BETTA) 2005.

The first REMA consultation, published in autumn 2022,[3] considered a number of potential market reform options to achieve a wide range of objectives. The second REMA consultation document,[4] published in March 2024, has narrowed the options under consideration, and has restated the overarching market reform objectives based around areas, outlined in Figure 5.

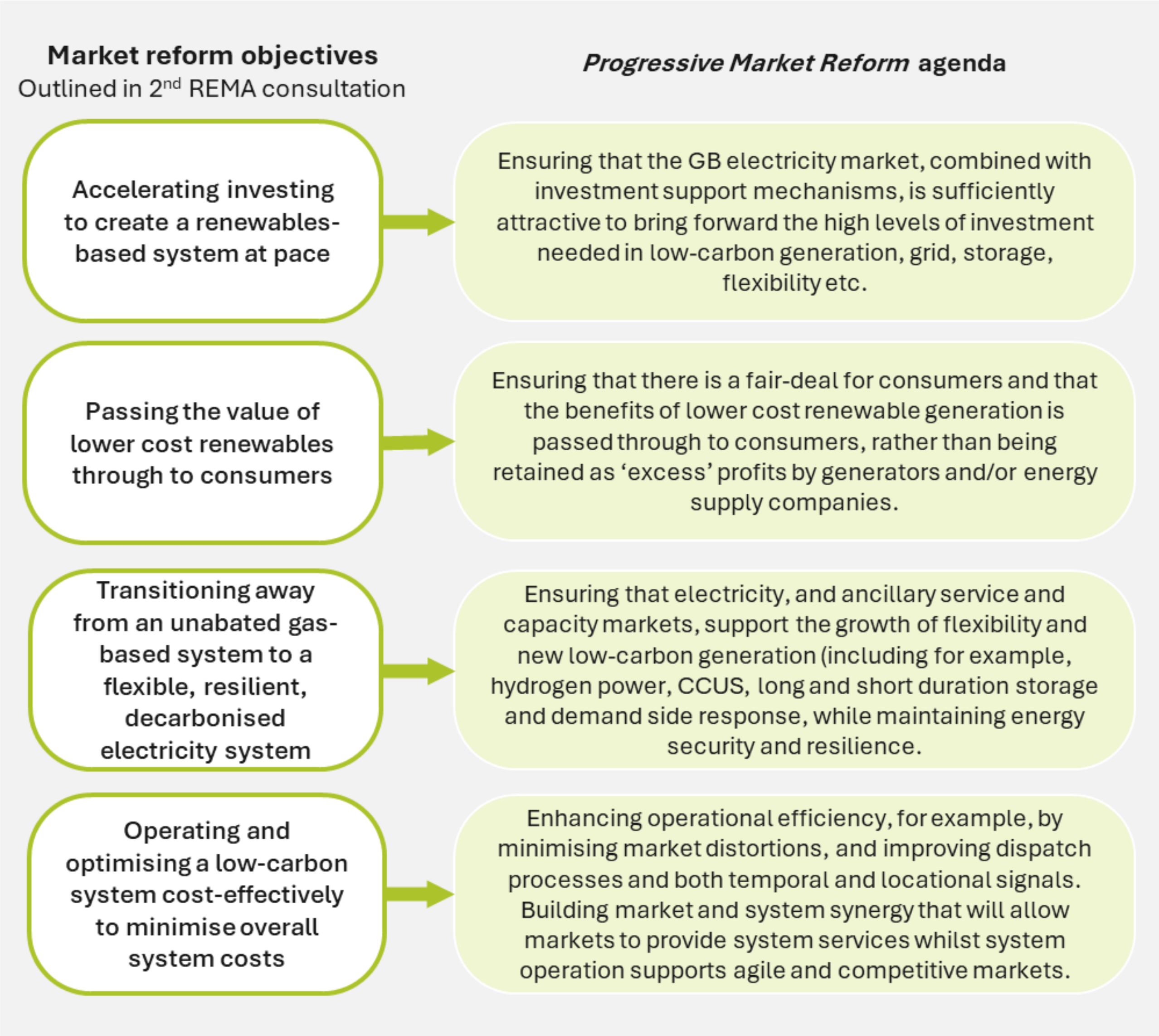

Figure 5. The four high-level REMA objectives. Source: Second REMA consultation March 2024.

[3] DESNZ REMA First Consultation October 2022.
[4] DESNZ REMA Second Consultation March 2024.

1.1 The initial REMA consultation

1.1.1 Radical versus incremental reform debate

The first phase of the REMA consultation has been dominated by a vociferous debate about whether the GB electricity market requires radical reform that would change the underlying basis of the market, or a more incremental package of reforms that would build on and enhance the existing market arrangements. A similar debate has been held across the EU, with the weight of the argument coming down on the side of incremental reforms, including the expansion of long-term PPAs and CfD contracts, and measures to promote greater market integration and interconnectedness.[5]

The early focus on radical options occurred in part because REMA was launched against the backdrop of the energy crisis and steeply rising wholesale prices, which in turn led to higher constraint costs, and added to the perception that the current market is 'broken'. This assertion differs from the rationale for market reform that was set out in the 2020 energy white paper Powering our Future,[6] which preceded REMA and focused more on ensuring market efficiency while continuing to support net zero investment in an era of high renewables and the potential for market price cannibalisation.

The radical reform options have included:

- **'Splitting the market'** to create separate pool markets for renewable energy and fossil fuel generation so as to break the real (and perceived) link between renewable energy and high-cost gas prices, and remove the occurrence of excess profits made by lower-cost generators at times of very high gas prices, as the market experienced during 2022.
- **A shift to a form of Locational Marginal Pricing (LMP)** which could be either nodal, probably based on hundreds of GB grid supply points (GSPs), or zonal, based on transmission network boundary areas (constraint zones), of which there may be a dozen or more at any one time.

[5] For a summary of EU reform proposals see E3G and Centre for European Reform.
[6] Energy White Paper Powering our Future 2020.

Proponents of incremental progressive reform have challenged the radical options. The arguments against radical reforms are discussed in more detail in Regen's REMA 2nd consultation response but the key points that have been raised include:

1. **The investment and ongoing commercial risk** introduced by radical reforms would severely impact the UK's progress towards net zero and its long-term energy security strategy. The nature of these risks has not been fully explored and quantified,6F7 but include increased revenue uncertainty, grid access risk, constraint risk, dispatch risks and policy development and implementation risks. A risk comparison with other LMP markets is difficult since investment risk will depend on the state of each market. A market that is relatively stable, with marginal levels of change, low levels of current and forecasted constraint and a history of building network capacity on time, would have a lower level of risk associated with LMP. The GB market, going through a rapid energy transition, a massive net zero investment programme with significant grid infrastructure requirements and current constraints, is definitely not in that position.

2. **The benefits claimed for radical options have been overstated and are hypothetical,** based on modelling assumptions, a questionable baseline distribution of assets, optimistic re-siting assumptions and a mismatch between network and generation capacity deployment, which do not represent a future market design. The most optimistic benefits claimed for LMP are highly sensitive to the scenario assumptions used and the modelled mismatch between generation deployment and network investment. While models can help identify and illustrate the potential sources of value, they should not be taken to provide a forecasted benefit case.[7,8]

3. A significant proportion of the **benefits claimed for LMP could be achieved, more quickly and with less overall investment risk**, as will be discussed further in this paper. These benefits include:

    a. **The optimal siting of assets** based on transmission network constraints, which could be better achieved via a combination of strategic spatial energy planning plus reforms to current locational signals within planning, connection queue management and network charging.

    b. **Benefits related to operational efficiencies,** which could be achieved through operational reforms to, for example, the BM, flexibility markets, interconnector operations and trading, and investment in control room and ESO market functions.

    c. **Benefits which are, in fact, a theoretical and doubtful transfer of value** from the producer to consumer, system operator and/or traders and hedge providers, which can be better achieved through the use of other value transfer mechanisms:

[7] FTI's assessment of investment risk has used a very basic cost of capital increase for certain assets of 0.5%. Others, including Frontier Economics and Strathclyde University, have suggested that a much higher cost of capital increase might be expected.

[8] For a critique of LMP benefit claims see Michael Pollitt – Comments on the FTI Report on the assessment of locational wholesale electricity market design options in GB August 2023.

CfDs, regulated asset base (RAB) models, cap and floor models, long-term PPAs, Green Pools and even, in extremis, windfall taxes.

4. **Costs and areas of value loss that have been ignored or undervalued,** including: implementation costs, cost of grandfathering existing assets and connection rights holders, costs and value loss associated with Financial Transmission Rights (FTRs) and other risk management approaches and, importantly, the likely loss liquidity – and therefore competition – in locational markets.

5. **The impact and treatment of consumers.** The degree to which consumers are exposed to increased volatility and locational price differentials has not yet been defined, but even if domestic consumers are not fully exposed to zonal pricing, there will likely be winners and losers across different consumer groups. The argument that 'overall all consumers would benefit' is misleading because the benefit case could easily be eroded, and there will be distributional impacts between those consumers who are able to take advantage of more volatile zonal prices and those who cannot. The latter group may include consumers whose circumstances provide fewer opportunities to shift demand, and those who may find themselves behind local network constraints. There is also a fairness issue, if revenue support costs are borne by all consumers (e.g. via a levy) but have a disproportionate impact within certain zonal markets. Overall, the impact for consumers has not been analysed in sufficient detail.

1.2 Second REMA consultation proposals

1.2.1 Split markets, zonal and nodal LMP

There has been significant disagreement about the relative merits and risks associated with radical market reform options. Evidence suggesting that the majority of stakeholders would prefer an incremental package of reform includes the initial REMA consultation response[9] and industry surveys conducted by other organisations such as Cornwall Insight, which concluded LMP is not the answer.[10]

Although it initially seemed politically attractive,[11] the 'split market' design option has received very little support and was dropped from the second REMA consultation. This is mainly because, apart from the high-level description given in academic papers,[12] there isn't an easy-to-implement market design that would achieve a general split of the GB wholesale market[13] and it was concluded that the consumer value benefits could be achieved more easily via other reforms.

Nodal pricing, the more granular form of LMP, was also dropped, mainly because it would be hugely complex and difficult to implement, and "due to the impacts it would have on investor confidence and the deliverability of our 2035 decarbonisation targets". The REMA team has also acknowledged that the benefits of nodal LMP may have been overstated: "Our assessment is also that the theoretical benefits of nodal pricing may be overstated through some modelling exercises."

At present there is no consensus that LMP is the right solution, no detailed design of how an LMP solution would be implemented and a low level of confidence that such a radical change could be implemented at a time of major energy transformation for the industry and for consumers. For these reasons, many industry stakeholders view LMP as a distraction that has already impeded investment and policy decisions when there are far more urgent issues to be addressed.[10]

At Regen's REMA event in April 2024, two-thirds of delegates polled favoured incremental reforms, as shown in **Figure 6**.

[9] Responses to the first REMA consultation published by DESNZ showed that 75% of responders supported the exploration of incremental reforms – a higher level of support compared to nodal or zonal LMP.

[10] Cornwall Insight, 2022. 'LMP is not the Answer'.

[11] Prime Ministers Johnson and Truss publicly supported a form of split market approach "People are being charged for their electricity prices on the basis of the top marginal gas price, and that is frankly ludicrous. We need to get rid of that system." *Boris Johnson*

[12] See for example Keay and Robinson, Oxford Institute for Energy Studies (2017)

[13] The original concept of 'green power pools' wasn't a general market split but collaborative power pools or shared PPAs for specific consumer groups or geographies. This still has potential as part of a local supply model.

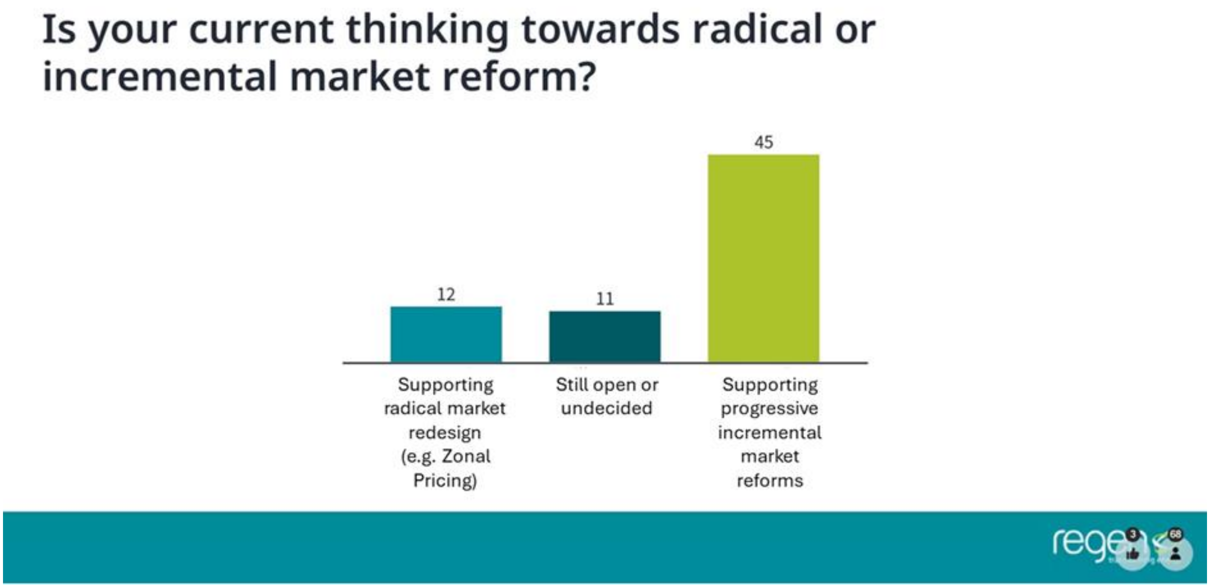

Figure 6. Participant responses on a progressive or radical market reform. Source: Regen REMA consultation event survey, 22 April 2024.

1.2.2 Zonal pricing

An option of zonal pricing has been retained, although the preferred design options for this, and their impact on other design choices, are still to be defined.

Zonal pricing could take the form of a relatively large number of zones, with mandatory centralised LMP-based market, loss of firm transmission rights, and full centralised dispatch, in which case it would have much the same risk and impact as full nodal LMP. Alternatively, it could take the form of just two or three zones and attempt to retain the current decentralised trading and dispatch arrangements within these and a form of market trading for network capacity between them, similar to approaches used for cross-border interconnectors within the EU single market. It's difficult, however, to conceive of an outcome where zonal pricing would be adopted with just two or three zones and retain current decentralised dispatch. The benefit case was presented alongside the second REMA consultation conducted by LCP Delta/Grant Thornton,[14] and based on 12 zones, with LMP pricing and centralised dispatch.

As DESNZ has acknowledged, the zonal pricing option is undeveloped and poorly understood by stakeholders, including its impact on consumers, flexibility, storage and distribution-connected assets. The impact that zonal pricing would have on other market reforms, including CfDs and RAB schemes, network charging, future interconnector design and PPAs, is yet to be assessed. In Regen's REMA event survey, only two out of 73 delegates polled thought that the "zonal design option was clear from the information provided" in the second consultation.

[14] LCP Delta/Grant Thornton, 2024. System Benefits from Efficient Locational Signals.

> "Our assessment acknowledges zonal pricing does not represent a singular well-defined market reform. There are numerous forms of zonal pricing, with the exact implementation of zonal pricing having the potential to greatly change both the costs and benefits of such a market reform." – **DESNZ REMA Options Assessment 2024**

The key rationale to retain zonal pricing as an option has been that it offers a potential value transfer to consumers (although this is challenged) and could address current and future operational inefficiencies associated with interconnectors and storage assets. Interconnector operation and efficiency is a key area of reform under any market design option. The benefit case based on providing better zonal asset-siting signals for long-term investment decisions has been challenged, given the lack of evidence as to their effectiveness, especially as GB energy policy moves to adopt more strategic spatial planning and proactive connection queue management.

The second REMA consultation document highlights both the potential benefits and risks of a zonal market design. The analysis provided by LCP Delta/Grant Thornton identifies a range of system benefits of between £5.2bn and £15.5bn for a zonal model over a 20-year period. In the higher benefit case, £7.9bn system benefit is from interconnector efficiencies and £5bn from better generation asset siting.[15]

The modelled benefits for zonal pricing reflect a set of hypothetical assumptions, scenario projections and a misaligned grid and interconnector investment plan. The asset siting benefits, which include c. 13 GW offshore wind relocating off the south coast of England, are unrealistic. As the authors acknowledge, the benefits claimed could be quickly eroded by an increase in investment risk, leading to higher costs of capital, delayed projects and other implementation and system costs that have not been quantified. **Critically, the impact that zonal and central dispatch would have on market competitiveness and liquidity has been largely ignored.**

> "Our analysis shows that a move to zonal pricing has the potential to bring benefits to the British electricity system and to households. However, these benefits may be offset by the additional risk premiums faced by investors, given the dramatic change to the way generators would be paid and the sheer scale of investment needed to reach net zero."
>
> "System cost benefits could be outweighed by increases in cost of capital. Increases in cost of capital of 0.3 to 0.9 percentage points result in a move to locational pricing becoming a net cost to the system."
>
> **– LCP Delta/Grant Thornton March 2024**[14]

[15] £5.2bn saving from the relocation of generation (core scenario), £7.9bn from interconnector operations and £2.4bn from battery operations. The benefit case does not include the cost of grandfathering or the increased transactional/hedging costs of a zonal system.

It is understandable that it has been difficult to produce a more robust benefit case for zonal pricing. Several academics have commented that, while the theory is persuasive, the evidence case behind LMP is extremely difficult to quantify, and, in areas such as asset siting, is very dubious.

> "We conclude that while the theory and modelling behind LMPs is strong, their wider theoretical rationale is less clear cut and the evidence on their impact in use is surprisingly weak." – **Professor Michael Pollitt, Cambridge University**[16]

Regen's view is that **zonal pricing should be dropped as an option**. If retained as an option, it would require another round of market design and a further consultation before any firm decision could be taken, adding to the level of risk/uncertainty and investment delay.

1.2.3 National wholesale pricing market

Both the Ofgem assessment of LMP[17] and second REMA consultation have concluded that a more realistic national pricing market model is needed rather than an assumption of a 'do-nothing' status-quo counterfactual. DESNZ has also stated that it's position is neutral between the different market options at this stage, with teams looking at both design options.

> "In the next stage of REMA, we will seek to work closely with industry, ESO/NESO, and Ofgem to develop both national and zonal models of wholesale market reform to enable a comparison between the two with the aims of designing models which can most appropriately allocate risk to market participants while delivering savings for consumers." – **Second REMA consultation**

Regen has welcomed the recognition and increased focus on developing a more realistic and ambitious reformed national market model. This focus on retaining a national market has been missing from the work to date and now needs to be taken forward with more emphasis on developing an ambitious but deliverable incremental programme of reform that can achieve the four key REMA objectives.

[16] Michael Pollitt, Cambridge University, 2023. Locational Marginal Prices for Electricity in Europe? The Untold Story.
[17] Ofgem's Assessment of LMP based on the FTI modelling analysis and supporting academic reviews

1.3 Current market arrangements

1.3.1 A brief history of the GB electricity market liberalisation

The GB electricity trading market is more liberalised, sophisticated and advanced than many other markets. Contrary to how it is sometimes described in the media and by commentators, it is not the case that the GB wholesale market has a single price, with every generator receiving the same wholesale price. The GB market can more accurately be characterised as a liberalised national trading market with decentralised dispatch, plus a secondary system balancing (central redispatch) market, known as the BM (BM).

The basic framework for the current GB electricity wholesale market has its origin in the New Electricity Trading Arrangements (NETA) that were across England and Wales in 2001, and extended to Scotland under the British Electricity Transmission and Trading Arrangements (BETTA) in 2004/5. The creation of a liberalised electricity trading market has created challenges for system operation, but it has also enabled GB to be one of the fastest-growing markets for decentralised renewable energy, and has supported the growth of small and medium-sized projects, as well as large-scale offshore wind.

One objective behind the NETA/BETTA reform was to move away from a centralised dispatch and a single 'pool' market arrangement, which was considered uncompetitive and inefficient, and to introduce new trading arrangements that would allow the market to establish prices through a variety of trading arrangements and, to a large extent, be self-balancing through decentralised self-dispatch. NETA also paved the way for more competition between energy supply companies, which could now more easily competitively purchase, trade and hedge their energy supply.

It is important for policymakers to recognise and understand the relative merits of the current market arrangements while considering the case for change.

The GB market is imperfect – the level of redispatch required being one area of contention – but NETA certainly did introduce a more competitive and dynamic market which allowed a very high degree of bilateral trading between market participants and, importantly, allows demand to be an active market maker rather than simply a price taker. The autonomy and freedoms the market provides has driven a diversity of business models – see Figure 7. A year after its introduction, it was estimated that NETA had reduced wholesale prices by 40%.[18]

Since NETA, trading liberalisation has changed the nature of the GB market substantially. Electricity can be traded over multiple time periods and by myriad bilateral bespoke and forward contracts between generators, off-takers and traders, as well as via a number of private

[18] Ofgem, 2002, The review of the first year of NETA.

day-ahead exchanges and intraday markets.[19] This has allowed a rich and complex trading ecosystem to develop, along with a good deal of innovation.

The ability of generators to easily access the market and to sell their energy in forward trading and under long-term PPAs has been a major factor encouraging the growth of renewable energy at both large and small scales. See Box 1.

A further key feature of the GB market is the ability of participants to continue to trade up to and beyond gate closure. This is a critical source of efficiency in a market with high levels of variable renewables, allowing generators (and their off-takers) to adjust their balancing position and make maximum use of renewable generation. A future market design that corralled the market into a day-ahead position, and/or added friction (or penalty or time limit) on intraday market rebalancing, would introduce significant inefficiency. Including the risk that available renewable energy would be foregone in favour of more expensive higher carbon generation.

Industry stakeholders have argued that GB market reforms should be moving towards later gate closure, shorter settlement periods and further liberalisation, to allow markets to fully optimise energy demand and supply.

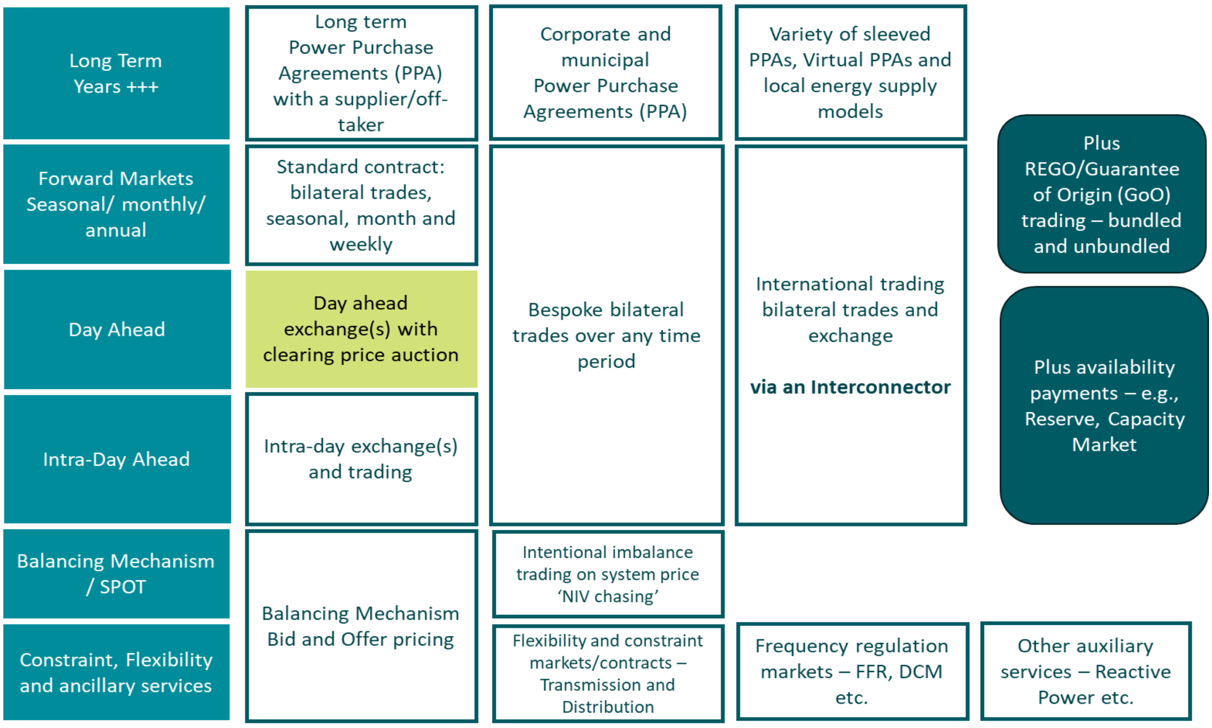

Figure 7. Overview of GB electricity short term and forward markets.

[19] According to Ofgem tracking, around 70-75% of trades are bilateral, with the rest taking place through exchanges. Electricity is traded multiple times with an average churn rate of 2-3 times traded between generator and end consumer.

Box 1: Growth of the forward PPA market and its role in supporting renewables.

Growth of the forward PPA market

Power Purchase Agreements (PPAs) have enabled generators to sell electricity either directly to customers or via 'sleeved' contracts through suppliers on a long-term price contract. PPAs come in a variety of forms and contract terms,[20] but are typically between two parties – one generating energy and one buying energy – and will include commercial details such as pricing, delivery schedules and what happens if the generator underdelivers energy.

There are different types of PPA, including:

- **Direct PPA:** Between a generator and the end user of electricity or an energy supply company, sometimes referred to as the off-taker.
- **Sleeved PPA:** An arrangement whereby a third-party supply company is involved to deal with the transfer of the electricity from the generator through the local distribution network to the buyer, and usually provides a balancing function.
- **Virtual PPA:** A purely financial instrument where two parties agree a 'strike price' at which the buyer pays the generator for energy they produce, although no transfer of energy takes place. The generator then sells their energy on the wider market. If the wholesale price they receive is less than the strike price agreed, the buyer pays the generator the shortfall. If the wholesale price is higher than the strike price, the buyer receives a payback from the generator.

PPAs can be fixed price or with an inflation index link to provide a high degree of hedging, or they can offer variable prices, often referenced to day-ahead electricity prices. Variable PPAs are an important tool to complement CfD contracts, ensuring that generators receive the reference price from the market as well as the CfD cashflows. In addition there may be cap and collar conditions and clauses related to risk premiums or negative price periods, etc.

The PPA market has become a significant enabler of renewable generation and is especially important for smaller distributed generators as a means to secure a long-term revenue steam and finance. By entering into a long-term PPA, generators and consumers are able to hedge against price volatility and trade the value of a long-term revenue stream for the generator, which is essential for investment, for lower-cost energy for the consumer. PPAs also play a key role for companies to decarbonise their energy supply, fulfil corporate social responsibility objectives and, in some areas, to qualify for government grants and subsidies (such as the Low Carbon Hydrogen Standard).

It's difficult to give an accurate estimate of the scale of the PPA market, but it has grown substantially since 2010. A recent study by Aurora[21] suggests that the GB PPA market may be second only to Spain in Europe, with an estimated 14 GW (24%) of renewable capacity under PPA terms.

It's positive that the role of PPAs has been highlighted in the second REMA consultation; **an efficient and growing PPA market is a key element of the progressive reform agenda**. As a minimum, policymakers must consider the impact that market reform would have on existing PPA contracts which could be subject to contract renegotiation due to change in law clauses.

[20] For more information about how PPAs have encouraged renewable energy and local energy supply models, see Local Authority Models for Developing Renewable Energy – Regen (2021).
[21] Role of PPAs in the GB Power Market – Aurora (2022), p5.

1.3.2 Overview of system operation – gate closure and balancing

Although the GB system operator no longer sets the merit order for dispatch, the move from 'the pool' with centralised dispatch to a market-first arrangement under NETA required the system operator to develop new tools, and new processes, to perform its remaining key functions:

- Managing the final real-time balancing of the electricity system
- Managing transmission grid constraints (and potentially distribution constraints)
- Ensuring system resilience and operability.[22]

The main toolset for the system operator to perform these functions are contained within the BM, supported by a number of ancillary markets (such as frequency response), which provide additional system services.[22] The GB market could, therefore, be described as a hybrid market which is led by a liberalised and decentralised wholesale market, but which, at a certain point in time, is 'handed over' to the system operator (ESO) which then manages the final balancing and operability of the system in the centralised BM.

The key hand-over point is referred to as gate closure, which is currently set at one hour before the delivery period.[23] At this point, market participants must submit their Final Physical Notifications (FPN) to the ESO, which includes their forecasted volumes of energy demand and generation, and their Bid and Offer[24] prices to be turned down or turned up in the secondary BM redispatch market.

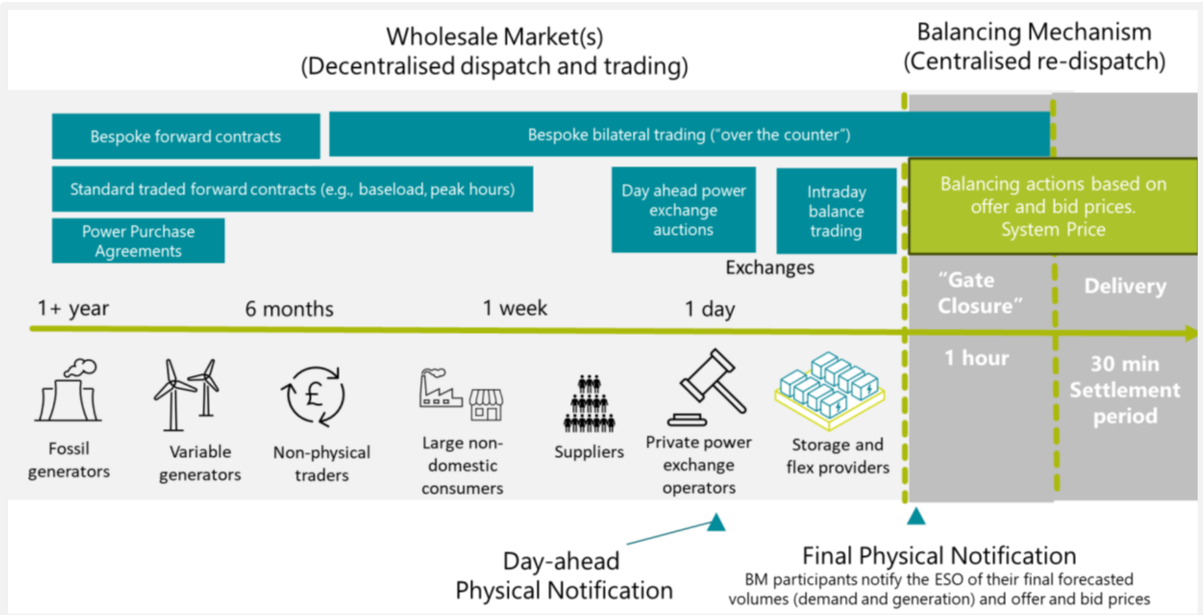

Figure 8. Simple schematic of GB trading environment.

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[22] Operability including frequency control, stability, inertia, constraint management, reactive power, reserve power, etc. For more information, see A Day in the Life of the Energy System 2035.
[23] Known as the Settlement Period, because the electricity system is currently 'settled' in 30-minute periods.
[24] Bid price to turn down generation or increase demand, offer price to turn up generation or reduce demand.

The BM is not the only way for the ESO to manage energy balances. It can also trade within the market ahead of the gate closure window if it judges that doing so can relieve system constraints or provide reserve services more cost-effectively. It can also contract for balancing and flexibility services in advance of gate closure (an example now being the new day-ahead Balancing Reserve service). Historically, however, the preferred approach has been to wait until FPNs have been placed and to rely on the control room to take actions within the BM following gate closure. For energy balancing actions, this has typically meant relying on the fleet of dispatchable gas (CCGT and OCGT) generators. For constraint management, this has involved turning down wind generation behind a constraint and turning up large gas plants on the other side of the constraint to rebalance the lost wind energy.

While, in theory, actions fall into one of these two categories, in reality, actions may be chosen that resolve multiple issues at the same time – for example, if the system has an excess of energy (an energy constraint) and a binding transmission constraint, reduction of wind generation behind the constraint can help relieve both.

The reliance on relatively large and inflexible[25] combined cycle gas turbine (CCGT) plants, which are easier to schedule and dispatch, and provide important system services, is partly an operational necessity and partly the result of legacy IT systems and clunky dispatch processes. This is now changing with the introduction of digital automation and new balancing tools such as the Open Balancing Platform, to allow multi-asset dispatch and thereby allow wider access to the BM and higher dispatch rates for storage and flexibility providers.

The ESO's preference to use post-gate closure actions within the BM is partly due to the lack of transparency and forward visibility within the intraday trading market, transactional costs and an understandable reluctance to take trading risks. There is also a concern that ESO trading could distort the market itself. This is changing, with the ESO now regularly trading within the intraday market and, where it can, with interconnector market participants.

1.3.3 A dynamic market or operational efficiency: a false dichotomy?

NETA marked a move towards market efficiency and liberalisation, which has widened market participation and enabled the expansion of decentralised generation. In the last decade the wholesale market has become more dynamic (and less predictable), with many more transactions in PPAs, forward and intraday trading.

The more dynamic and open GB trading market has benefited renewable energy and energy storage providers in a number of ways (see Box 2) – for example, by allowing market access and the direct trading of electricity via PPAs, and is at least a part of the success story for GB power decarbonisation, and growth of the battery storage market.

[25] Inflexible, compared to a battery, in the sense that they require minimum run-times and power output levels and are therefore fairly blunt instruments when it comes to finetuning constraints or system balances.

In the case of battery storage, stacking revenues from wholesale arbitrage, balancing and flexibility are beginning to provide a significant portion of the investment case for longer-duration assets. This is in contrast to central dispatch markets like the island of Ireland, where batteries are still predominantly providing ancillary services.[26]

Box 2: Features of the GB market that encourage renewable generation and flexibility

Seven key features of the GB market that have benefited renewable generators and low-carbon flexibility
1) Firm connection agreements – the ability of a project developer to secure a firm connection date with financially firm access to the market. Albeit that connection lead times are now extended and, for distribution-connected assets there has been a significant upfront connection charge, having a firm connection has enabled developers to secure investment capital. **Non-firm connections** can be also bankable, and may help accelerate connections, but only where constraints are infrequent, time limited and can be forecast with relative confidence.
2) Access to the electricity market via both long-term and short-term markets. The ability to sell energy, relatively easily,[27] on long-term PPA contracts has allowed many smaller generators to enter the market with a degree of revenue certainty. New projects are willing to give up significant value – via lower PPA prices – to obtain a long-term revenue stream.
3) The ability to sell electricity directly to an end consumer or off-taker, or via trading intermediaries[28] – which has made PPA-backed renewable energy procurement and bundled certificates (REGOs) attractive as part of a decarbonisation, green tariff or CSR strategy.
4) Easy and open trading right to the delivery period. The ability of generators, off-takers and flex providers to trade right up to the delivery period has allowed better balancing, more efficient use of variable generation and opportunities for storage and flexibility providers.
5) Relatively dependable and bankable forward price forecasts. Although not perfect, forward national power price projections, mainly produced by independent third parties, are reliable, especially when supported by a long-term (three to five-year) PPA, to raise debt finance. This may become more difficult as negative pricing and greater price cannibalisation occurs.
6) Self dispatch for energy storage providers – which has opened up opportunities for asset optimisation, revenue stacking and price arbitrage.
7) Increasing access to ancillary service, balancing and flexibility markets for both national control room and distribution system operations. Although access has been imperfect, balancing and flexibility markets are becoming a significant revenue stream for storage and flexibility providers.

[26] For a discussion about storage in the Irish electricity market see Cornwall Insight Review of deployment of long-duration energy storage in the electricity sector in Ireland pages 20-22.
[27] There are issues with liquidity and challenges accessing long-term PPAs, which is one area of progressive reform.
[28] Example trading intermediaries include Smartest Energy and Renewable Exchange.

GB market dynamism and innovation is partly a response to the growth of more variable, weather-dependent, renewable energy. It also reflects the fact that there are now many more market participants (including storage and flex providers, paper traders, energy suppliers and aggregators), greater levels of interconnection with neighbouring markets and a higher level of trading sophistication (and risk taking). There has also been an increase in the number of smaller generators and storage assets that are connected to the distribution network (embedded generators), some of whom do not participate in the BM directly but sell their energy through trading platforms and off-takers.

This more varied and dynamic market has been enabled by a revolution in digitalisation, data analysis and trading platforms, which has not yet been matched by an equivalent investment in system operation capability.

Tensions between the dynamic market and efficient system operation

It could be argued, however, that market liberalisation has been achieved at the expense of some aspects of efficient system operation. This is evidenced by periods with high level of redispatch, volatility in system prices, increased balancing risk for participants and a rise in both constraint management and balancing costs. These instances of market/system inefficiency have been greatly exacerbated during the energy crisis period after September 2021, mainly because, in a period of higher wholesale prices and speculative behaviour, each balancing and system action taken by the system operator has a higher price tag.

A key challenge under current GB bilateral trading and self-dispatch arrangements is that the system operator does not have full visibility of which generators intend to run, and their volumes, until gate closure and Final Physical Notification, currently one hour before delivery. Even at gate closure, the system operator may have limited visibility of those distribution-connected assets (embedded assets) that do not participate in the BM. There are also concerns that the physical notifications given by variable wind generators may not be wholly accurate, costing £14 million of direct costs and £50 million of indirect costs (e.g. holding more reserve) in 2023.[29]

The loss of visibility becomes more acute during periods of volatility and system imbalance, and especially during negative price periods,[30] with high volumes of intraday bilateral trading and some speculative activity.[31] The dispatch challenge is also heavily driven by the elements of time, forward visibility,[32] forecast and physical notification accuracy, poor metering, and dynamic parameters that affect asset availability, liquidity and control room capability.

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[29] An area of reform already in progress, and led by the ESO, is to improve the level of day-ahead and FPN accuracy. See Two-step process to improve PN accuracy.
[30] A good example of a loss of transparency occurred during a negative price period on 29 December 2022, when three offshore wind farms that were expected to be offline for 6-8 hours began generating after 45 minutes.
[31] Speculative activity can include Net Imbalance Volume (NIV) chasing when market participants may put themselves in an imbalance position in order to take advantage of high (or low) system prices.
[32] For FPN accuracy and operation challenges faced by the ESO see Operational Transparency Forum, 5 June 2024.

The problem of market visibility and access to some assets has been identified as one of the key sources of operational inefficiency in the current market arrangements[33] and has led to calls for more radical market reform, including a shift back to a more centralised dispatch and to push some operational risk back onto wholesale market participants.

Undoubtedly, the challenge to operate the system securely and efficiently has been made more difficult by the growth of more variable renewable energy, as well as the sheer number of new market participants. This can be clearly seen in the volume of redispatch actions now taken through the BM and the rise in balancing costs.

By contrast, in a centrally dispatched system, based around a mandatory day-ahead market, the system operator can factor in and, in theory, co-optimise, balancing network constraints, response and reserve and other operational requirements when setting the dispatch merit order. To reduce redispatch, the system operator could regulate, and potentially disincentivise, any intraday adjustments via secondary trading with a buy-out mechanism. The system operator could almost remove the need for redispatch and balancing, albeit at the expense of market efficiency.

In theory, central dispatch is an appealing market set-up for system operation, and harks back to the historic centralised system approach, but a return to a full central dispatch model would have a number of challenges, including:

- Whether the ESO has the capability to 'optimally dispatch' all the assets, taking account of their various technical constraints, and would be able to do this as successfully as the market. If this is not the case, central dispatch would lead to a loss of optimality in terms of asset operation as owner/operators (those who know their assets best) lose control over their operation.
- A significant reduction in the potential for innovation. For example, it would potentially remove the role of ‘flexibility optimiser’ from the market and give this function to a market operator that may have less incentive for fast innovation and instead act in a relatively conservative way to prioritise security of supply.
- A huge step change in centralised IT infrastructure of the type that the UK public sector is not known for delivering effectively.

While central dispatch has some control advantages for the system operator, the reality is that neither a fully centralised nor fully decentralised market is likely to be optimal, or even achievable, without placing significant restrictions on market activity and impacting investment.

[33] For a discussion around market transparency see Afry’s GB Scheduling and Dispatch – A Case for Change, May 2024.

Providers of flexibility and energy storage are especially concerned that a shift back to central dispatch would negatively affect their business case and ability to optimise assets.[34] It is notable that energy storage providers operating within the island of Ireland market, which operates a form of central dispatch but not zonal pricing, have not made the same progress to develop arbitrage and balancing business model opportunities as has been seen in GB.[35]

There is, however, a broad cross-industry consensus that both the market and system operation processes need to be enhanced and further digitalised. Market transparency, improved control room functions, better forecasting, physical notification accuracy and enhancement to the BM, alongside new balancing and constraint management services, all feature strongly in the progressive market reform agenda.

1.3.4 Revenue support models for low carbon and energy security

After NETA, the next big change in the GB market arrangements was the Electricity Market Reform package of 2012/13, which introduced the Contracts for Difference (CfD) scheme and the Capacity Market (CM). Both have, so far, been considered a success.

CfDs – success to date, but challenges ahead

The CfD, despite recent auction travails,[36] has brought forward a significant capacity of offshore wind, as well as onshore renewables, with falling strike price costs. Significantly, in the context of consumer value, the CfD includes a value-sharing arrangement with consumers – via the negative payment clause – which, assuming competitive auctions, offers consumers a fair and low price for energy in exchange for long-term revenue certainty for the generator.

CfDs are not suitable for all technology types – they should not be used for dispatchable generation and have, so far, proven less attractive for new pre-commercial technologies such as floating wind – but there seems to be little appetite to move away from a CfD-type arrangement for renewable generation, and many EU countries are moving towards this model. This has been reflected in the second REMA consultation, in which an enhanced CfD has been confirmed as the main mechanism to support investment in renewable generation.

The CfD mechanism has evolved in a number of areas since the first contracts were awarded in 2012/13. Since then, over 33 GW of generation has received CfD contracts, including almost 20 GW of offshore wind, over 4 GW of solar, 3.2 GW of nuclear at Hinkley C and over 3 GW of onshore wind. The first CfD contracts (which included Hinkley C and the FIDER offshore wind projects) were awarded via bilateral negotiation and administrative strike price setting, while

[34] See Electricity Storage Network response to the second REMA consultation.
[35] For a discussion about storage in the Irish electricity market see Cornwall Insight Review of deployment of long duration energy storage in the electricity sector in Ireland, pages 20-22.
[36] The allocation round 5 CfD auction was a success for onshore wind, tidal and solar, but failed to attract bids for offshore wind. The reserve strike price (the ASP) was set too low, given cost increases in the supply chain and capital markets.

later awards have been allocated via competitive auction rounds, which have seen rapidly falling strike prices.

A further significant change to the CfD has been the introduction of new negative price rules, which have limited the revenue support payments during periods of overall negative wholesale prices. Negative price rules were designed to reduce market distortion and have exposed generators to additional market risk, but may also have created their own distortions in market behaviours, which have made negative price periods less predictable for the system operator.

Although the CfD scheme has been considered a success, and is now being emulated in other markets, in terms of the wider market design it faces a number of challenges which have been identified both through the REMA consultation and through ongoing CfD reforms:

1. How can CfDs continue to **reduce investment risk and accelerate the deployment** of low-carbon generation against a backdrop of increased market price and volume risk? Or, to flip this question, what is the appropriate level of market risk that will achieve the UK's investment targets while securing the optimal cost of energy for consumers?
2. How do CFDs value **'non-price factors'**, including economic development, UK and regional supply chains, environmental value and wider system benefits?
3. How do CfDs affect **market behaviour and create potential distortions** in the market, such as negative price periods and the loss of liquidity in forward markets?
4. Do CfDs also **inhibit generators from participating in ancillary service markets**, or 'behind the meter' type applications in storage and hydrogen production?
5. If nearly all new generation is CfD-backed, does this create a **more fundamental market distortion** – e.g. putting non-CfD projects at a competitive disadvantage or preventing other forms of forward market hedging? And if so, is this an issue?

Capacity Market – investment in low-carbon capacity and flexibility

The basic CM design also seems set to continue through the REMA process, but it may need to evolve significantly, both to ensure competition and to increase investment in new low-carbon technologies, including storage, hydrogen generation and flexibility. The primary purpose of the CM is still to ensure security of supply, but getting the balance right between a technology-neutral approach that may favour existing fossil fuel plants versus a scheme that will also support investment in low-carbon dispatchable generation, storage and flexibility will be key.

Market reform challenges for the CM include questions around:

1. **Value for money.** Recent auction prices have risen sharply as the government and system operator try to strike a balance between buying capacity margins and maintaining CM auction competition. New delays to Hinkley C and the slow uptake of new CCUS plants is likely to increase CM prices over the near term.
2. **Support for low-carbon and flex.** Should CM auctions have factors, allocations or other measures to favour new low-carbon technologies?

3. How quickly should the CM introduce **limits on unabated fossil fuel technology** (e.g. contract time limits or CM payments that are dependent on a decarbonisation plan)?
4. In the longer term, should legacy fossil fuel plants be moved out of the CM scheme and put into a **strategic reserve** as part of their end-of-life (or pre-conversion) management plan? This may be cheaper for the consumer while allowing generators who do not participate in the wider energy market to be kept in standby mode for energy security.
5. **What type of stress events should a future CM aim to secure against?** The current approach aims to ensure against a four-hour deficit of generation over demand across the whole GB system (sometimes called generation adequacy). How should future stress events be defined, and what other characteristics of capacity providers should be considered? For example, should a future CM aim to secure against an 8, 12, or 24-hour stress event? And should the ability to ramp quickly, provide inertia, or support voltage and stability through delivery of reactive power be considered when awarding CM contracts?

While both CfDs and the CM remain fundamental building blocks within the progressive reform agenda, a detailed assessment of their performance and design is needed, with potentially significant enhancements.

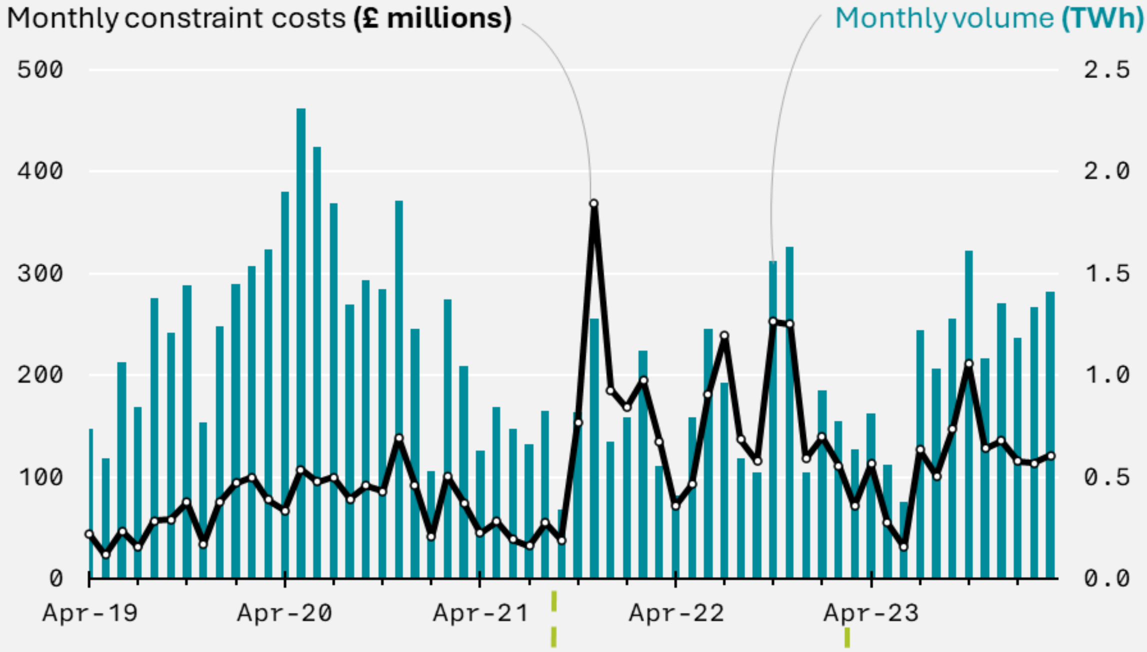
1.3.5 The rise (and fall?) of constraint management costs

The rise of constraint management costs, especially during the energy crisis of 2021/22, has given the system operator and energy policymakers cause for concern. There is some debate, however, about whether constraint cost increases should be considered a weakness or failure of the wholesale electricity market, or as a symptom of a wider misalignment between the deployment of generation and the build-out of network capacity, which has then been exacerbated by the steep increase in electricity wholesale prices and the cost of predominantly using large gas generators (CCGT plants) to manage constraint-induced system imbalances.

Some degree of constraint is an inevitable consequence of managing energy flows without necessarily having sufficient capacity to meet all loads at all times. A system without any level of constraint would not be economically efficient. However, the rise in the cost of managing generation constraints, first because of a delay in network build[37] (especially from Scotland to England) and second because of a very steep rise in wholesale prices, has raised this issue to prominence. GB has been slow to build transmission capacity to accommodate new generation and has then had to pay a significant cost to turn up gas-fired power stations to replace cheaper and lower-carbon generation (mainly wind energy).

[37] Especially the 'bootstrap' connections between Scotland and England such as the Western Link, which was delayed for two years from 2017 to 2019.

The impact of the energy price crisis on constraint management volume and costs
April 2019 to March 2024



	Pre energy price crisis Apr-19 to Aug-21	Energy price crisis Sep-21 to Feb-23	Post* crisis Mar-23 to Jan-24
Avg Monthly Constraint Volume (**TWh**)	1.24	0.86	1.07
Avg Monthly Constraint Cost **(£ millions)**	70	164	113
Avg Constraint Cost **(£/MWh)**	56	190	113
Avg Wholesale Price **(£/MWh)**	48	195	81

Figure 9. Constraint management costs and volumes of energy 2019-2024. Source: ESO monthly balancing cost reporting MBSS datasets.

As Figure 9 shows:

- **In the period from 2019 to 2021**, before the energy crisis, generation constraint volumes had increased to an average of around 1.2 TWh per month and a cost of £70m per month (£840m per year), or circa £56 per MWh of managed constraint – a little above the average wholesale price.
- **During the energy crisis period, from September 2021 to February 2023,** constraint costs jumped to around £169m per month (almost £2bn per year pro rata), despite constraint volumes actually falling, leading to costs of around £190 per MWh of managed constraint.
- **Post crisis, since March 2023,** average constraint volumes have risen again to just over 1 TWh per month (still less than volumes seen in 2019/20) but the cost of constraint management has fallen in line with falling wholesale prices, to around £113 per MWh constraint, with overall constraint costs now running at around £1.3 billion per year.

In summary, the big increase in constraint costs during the energy crisis periods has been driven by wholesale prices, and not an increase in constraint volumes.

So while the volume of generation constraint actually fell in the period since 2019, the per-unit cost to manage constraint actions jumped significantly. The reason why this happened gets to the heart of one of the key limitations of the current GB market and system operation: GB is still heavily reliant on large gas CCGT plants, which have minimum run times and minimum power output limits, to provide the bulk of balancing services, including to turn-up gas generation to replace constrained wind.[38] If, for example, a wind farm is turned down in Scotland, the payment made to the wind farm is effectively capped (via the Transmission Constraint Licence Conditions) at its lost net revenue (including support payments). However, the cost to turn up a gas-fired power station to replace that lost electricity is set by the short-term market. So, through the energy crisis, we were replacing low-cost, and low-carbon, wind energy with very high-cost gas generation.

Will constraint costs continue to rise?

Looking forward, there are a lot of factors that could lead to a rise or fall in constraint costs, including the rate of generation deployment, the rate of network infrastructure construction, connection queue management, changes to wholesale prices and steps taken by the ESO (and industry) to reduce constraint costs and apply new innovation to the constraint management problem.[39] Clearly, the alignment of generation deployment and network capacity build is going

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[38] Analysis by Delta LCP, Regen and others suggests that CCGT plants provided over 80% of balancing services during the energy crisis period. Modo, Arenko and others have identified that, in many instances, lower-cost assets have been 'skipped' in favour of CCGT plants, for operational reasons and because of control room data, process and IT limitations.

[39] For a good summary of the various factors affecting constraint costs and wider balancing costs, see ESO Balancing Costs: Annual Report and Future Projections May 2024.

to be the critical driver of constraint volumes, with wholesale prices projected to fall but remain above pre-crisis levels.

Projections produced by the ESO in 2021,[40] which have largely been replicated in the modelling to support radical LMP options, show constraint costs rising to around £2.5bn per year by the mid-2020s and to £3bn per year by 2030 under a FES 2021 Leading The Way scenario, combined with the Network Options Assessment (NOA) 7 network investment plan.

The £3 billion annual constraint cost figure has been reported widely, and has become one of the main justifications for radical market reforms, but there are several reasons why this high projection may be considered a worst-case scenario:

1. **Network investment is shifting from a reactive to a proactive mode**, as evidenced by the new emphasis on holistic network design (HND), the Accelerated Strategy for Transmission Investment (ASTI) and, in the near future, an SSEP combined with a Central Strategic Network Plan (CSNP). There are also a number of policy initiatives following the Winser Report[41] designed to speed up network infrastructure build. Of course, having plans and policies does not guarantee delivery, and there is still a risk of late construction, but at least the intention is now to get ahead of the buildout of new generation, especially for the large-scale projects like offshore wind, leading to ESO updated projection of constraint costs rising in the 2020s but then falling again to 'around £1bn per year' in 2030:

   > "The HND [The Pathway to 2030] has recommended significant investment in the onshore transmission network, including the requirement to accelerate the delivery of 11 major transmission schemes ahead of the TO's current delivery forecasts to the year 2030. The combined effect of a new offshore transmission system and the acceleration of onshore reinforcement projects causes a significant drop in constraint costs in 2030 to around £1bn per year." – **ESO Modelled Constraint Costs 2022 NOA 7 Refresh**

2. **Moving from connect and manage to a managed queue.** On the generation side there has already been a shift away from a 'connect and manage' approach, whereby generation was allowed to connect early, before the buildout of transmission capacity, on the basis that constraints could be economically managed. Generators connected to both the transmission and distribution networks are now more likely to face a significant connection lead time and to join a queue of projects awaiting new network capacity, or to be offered a non-firm contract to connect early.

3. **Reforms and system innovation to reduce the occurrence and cost of constraints.** Projections based on the cost to manage constraints during the energy crisis would be expected to fall as wholesale prices decrease, and this has already started through

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[40] ESO Modelled Constraint Costs 2022 NOA 7 Refresh.

[41] Electricity Commissioner (Nick Winser) Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations.

2023/24. In addition, the positive news is that there are lots of ways that both the volume, and the cost of constraint management actions, can be reduced. These have been documented by Regen and others in a number of recent publications.[42] The solutions that have been identified in these studies – for example: better planning, expansion of the BM, control room enhancements and the development of new flexibility and local constraint markets – are included in the agenda for progressive market reform package discussed in Theme C.

Many of these reforms are already in progress, including the ESO's new Open Balancing Platform, which should, when fully implemented, allow many more storage and flexibility providers to compete with CCGT plants in the BM and is a step towards a more agile and efficient flexibility/balancing market. There are also a number of innovations coming through the ESO's Thermal Constraint Collaboration project, which could reduce the occurrence of constraints by making better use of network capacity and provide the ESO with additional tools to manage constraints.

In its latest annual projection of balancing costs (which includes constraints) the ESO has identified c. £18bn of savings that could be made in the period to 2030.[43]

4. **Regulatory reforms and changes in constraint payments.** Overall, there has been a tightening of the rules and application of the Transmission Constraint Licence Conditions (TCLC), including steps to remove potential gaming of the market by both constrained generators and by CCGT plants. This has included some significant fines for wind, CCGT and other generators who may have inflated generation forecasts and/or turn-down bid prices.[44]

   A further regulatory step to reduce reported constraint management costs is contained in a proposed code modification,[45] which would remove subsidy and support scheme payments from the allowed constraint revenue recovery under the TCLC, thereby reducing the bid prices submitted to turn down renewable generation. Generators would still receive their subsidy via another payment, but this proposed reform would reduce prices and revenues that could be earned by storage and other flex providers. Turn-down costs may also fail to reflect carbon prices and other societal costs of turning down renewable generation.

[42] See, for example, Regen's Presentation to ESNZ Select Committee January 2024 and Seven Solutions for Constraint Management 2022. Also Energy Landscape's constraint management report for Scottish Renewables, 2024.
[43] ESO balancing costs: Annual Report and Future Projections, May 2024. For a list of cost reduction initiatives see ESO Balancing Costs Portfolio Feb 2024.
[44] See, for example, DRAX Pumped Storage, EPSHB CCGT, Dorenell and Beatrice Wind farm penalties.
[45] Code modification P462 – and analysis of battery impacts by Modo

1.3.6 Markets for ancillary, balancing and flexibility services

Alongside reforms to the balancing market, the ESO markets team and Distribution System Operators (DSOs)[46] have been active in the development of new markets for ancillary services and flexibility.

A notable milestone was the introduction, in 2016, of a new market mechanism for frequency response. The Enhanced Frequency Response (EFR) service has been hailed as a success both because it jump-started investment in new commercial-scale batteries and because it has led to a significant reduction in frequency response service prices. EFR has since been replaced by a new suite of dynamic frequency response products. Meanwhile, over the period from 2016 to the end of 2023, GB battery storage capacity has grown from little more than zero to over 3.5 GW.

DSOs have led the way in the procurement of flexibility services via various auction platforms, the identification of forward constraints and the purchase of flexibility via long-term call-off contracts. So far, distributed flexibility markets have focused mainly on demand constraints, the objective being to impact the timing of network investment, but this model could be extended to enable the optimisation of physical asset investment and flexibility solutions.

1.3.7 Interconnector strategy and operational performance

One area of widespread agreement is that the strategy and use of Interconnectors and Multi-purpose Interconnectors (MPIs) in the GB market needs a root-and-branch review, and reform of both the overall GB interconnector build strategy and the way in which interconnectors operate.

Interconnector issues and concerns that have been raised include:

- The lack of an overall GB interconnector strategy and system architecture – which could lead to ICs and MPIs being built in the wrong place and to inappropriate timescales, or not being built where needed.
- The lack of strategic planning and coordination with EU IC partners including the island of Ireland,[47] Norway, France and other EU countries within ENTSO.[48]
- The number of development proposals for ICs which have been rejected for revenue support by Ofgem,[49] suggesting that the market-led approach to development is not working and a more strategic approach is needed.

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[46] DSO – system operations on the GB distribution networks: SSEN, SPEN, NGED, UKPN, ENWL, NPG.
[47] GB does have a ministerial MOU to work with the Island of Ireland to coordinate energy and IC strategy and investment, but there is very little evidence of this working in practice.
[48] GB has left ENTSO and does not appear to be participating in the development of the EU regional ICs plans or Offshore Network Development Plan.
[49] Ofgem has recently published a minded-to decision to reject six out of seven third-round IC proposals for Cap-and Floor support, including two to the island of Ireland.

- Concerns regarding Ofgem's methodology used to assess IC value, including the choice and use of scenarios, constraint modelling, valuation of energy security benefits and consideration of consumer value in Northern Ireland.
- The lack of alignment between IC development and the investment in both offshore and onshore network transmission, and omission of ICs from the current round of Holistic Network Design. It is understood that ICs will form an integral part of the future SSEP and CSNP.
- The 'decoupling' of IC trading that has occurred since Brexit and which has led to trading inefficiencies and capacity underutilisation.
- Limitations, and the high cost, of ESO interventions to affect IC flows and capacity – which mean that IC assets, which ought to be able to provide flexibility, currently do not participate in the BM and so are adding to system costs.
- Misalignment and limitations of IC markets, vis-a-vis wholesale trading, which means that IC flows may at times run contrary to GB wholesale market price signals. An example being the North Sea Link Interconnector, which does not currently allow intraday trading – an issue the Norwegian ESO Statnett has acknowledged and is now proposing to address.[50]
- The potential that ICs could be built without adequate onward onshore transmission capacity and therefore begin to flow into part of the GB network that is already constrained.

The last point about ICs flowing into, or out of, parts of the GB network that are already constrained has been one of the key benefit areas identified for zonal pricing. Modelling produced for DESNZ suggested that, over 20 years, up to £8.1bn in IC-related operational savings could be made if zonal pricing were implemented, compared to a counterfactual in which new ICs are built but continue to not participate in the BM.[51]

It is not clear from the information provided by DESNZ which new ICs have been modelled or whether their location and time of construction has been coordinated with transmission network investment within an integrated infrastructure plan. A limitation of modelling is that it is possible to inflate zonal benefits by modelling hypothetical ICs, e.g. linking Norway to currently constrained networks in Scotland. Nevertheless, the potential of ICs to flow into constrained areas needs to be addressed, and this is one of the key challenge areas for progressive market reform.

1.3.8 Challenges and opportunities in the current market

In summary, the current GB market is not perfect. There are lots of areas for reform and enhancement (some of which are already in progress), but equally it is wrong to say that the current market is 'broken' or cannot be fixed without a complete redesign.

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[50] See Montel news report Norwegian TSO plans intraday trading on 1.4 GW UK link.
[51] LCP Delta and Grant Thornton System Benefits from Efficient Locational Signals, 2024.

The argument that the current market arrangements of bilateral trading are inconsistent with efficient operation only holds true in a ‘do nothing’ counterfactual. In fact, across every aspect of system operation – balancing, constraint management, interconnector flows, ancillary services and provision of flexibility – there are significant opportunities to improve and enhance current operation, while maintaining a competitive and dynamic wholesale market.

The debate around REMA and market reform more broadly needs to move away from a false dichotomy between a dynamic liberalised market and efficient system operations. While going backwards to a central dispatch approach would lose key aspects of the current market arrangements, equally, operational challenges cannot be ignored. The optimal market design would retain and enhance GB trading arrangements but do so in a way that provides the system operator with greater control and visibility, with the tools, capability and markets to ensure system resilience and operability, minimise carbon emissions and make best use of least-cost flexibility.

These outcomes and objectives are at the heart of the progressive market reform agenda that is outlined in the rest of this paper.

1.4 Overview of the progressive market reform agenda

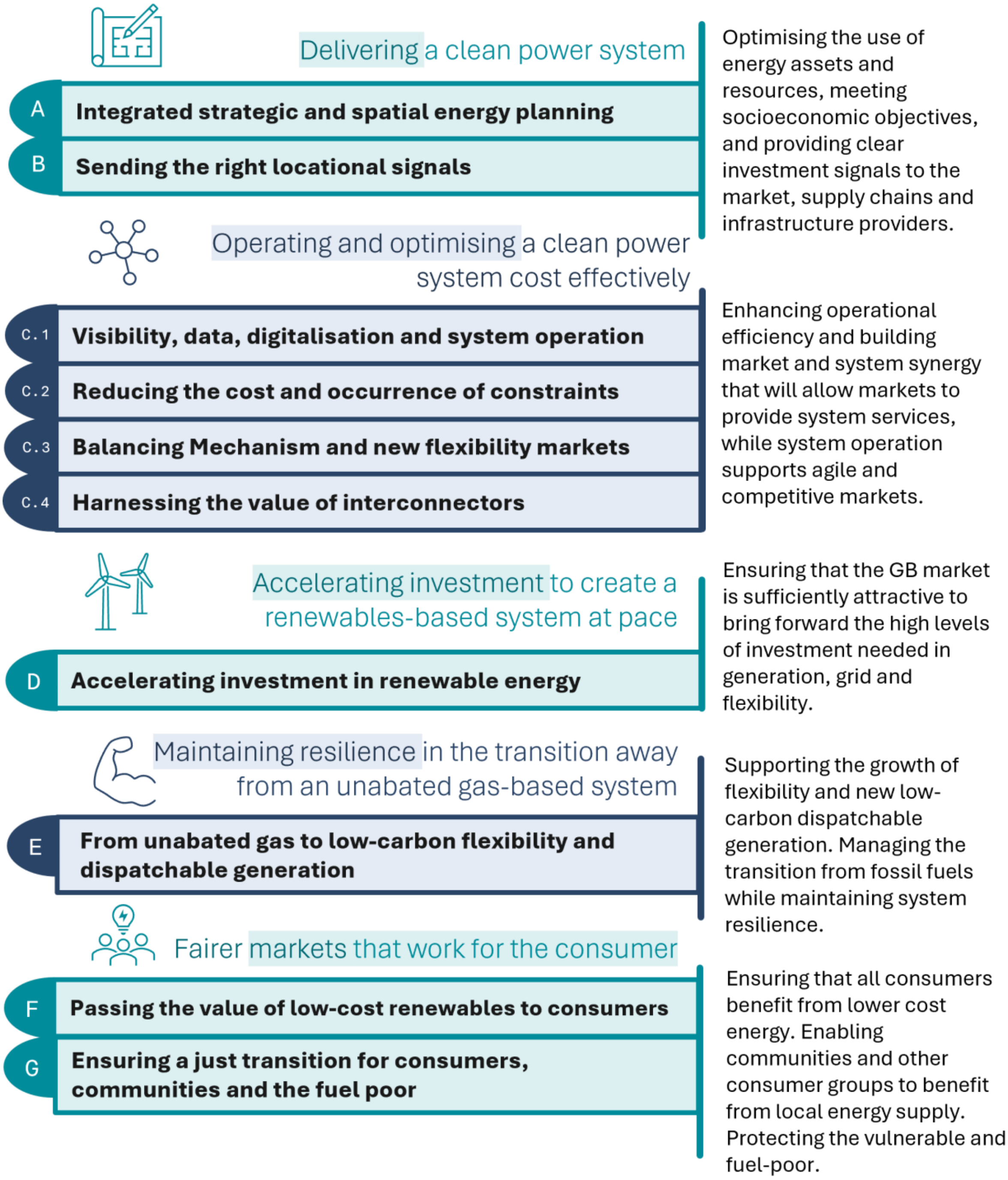

Figure 10. An outline of the progressive market reform agenda, broken down into themes one to seven, which are detailed in the following sections.

Progressive market reform would bring a significant and meaningful change to the electricity wholesale market, revenue support arrangements, system operation and ancillary markets.

The core objectives for the progressive market reform agenda are based on the four REMA market reform challenges set out in the second consultation, with the addition of an overarching objective to deliver a net zero energy system and the extension of the consumer value objective to include more progressive themes around a just transition, fuel poverty and local energy supply, which are likely to be a high priority for the incoming government and for consumer stakeholders.

Against each of the reform objectives, we have broken the progressive market reform agenda into key topics and themes which address the market challenges and issues discussed in Part 1 of this paper.

The division between agenda topics is potentially misleading because the reform initiatives overlap and are interdependent. The progressive market reform agenda should be viewed as an integrated programme of actions that will require ongoing governance and coordination.

Rather than lacking ambition, the reforms that have been identified in the areas of constraint management, network charging, flexibility markets, the BM, dispatch and operations, digitalisation, enhanced CfDs, new CM arrangements and interconnector reform would constitute a very significant reform package. This is especially true when put alongside other reform initiatives in connections, network planning and investment, strategic spatial planning, regional planning, new support mechanisms for long duration storage, hydrogen and CCUS, retail market reform, network charging and the creation of the NESO.

It would be wrong to characterise progressive market reform as maintaining the status quo or fiddling at the edges to avoid major reform. The fact that it picks up on existing themes and reform initiatives that are already in progress, such as the ESO markets and flexibility strategy, is a positive which should point to an accelerated timetable for reform delivery, rather than a lack of ambition.

Progressive Market Reform Agenda

Theme A

Integrated strategic and spatial energy planning

A fundamental foundation of an efficient GB energy market is that it will operate within the context of an overarching strategic and spatial plan for the delivery of net zero, energy security and supporting infrastructure investment.

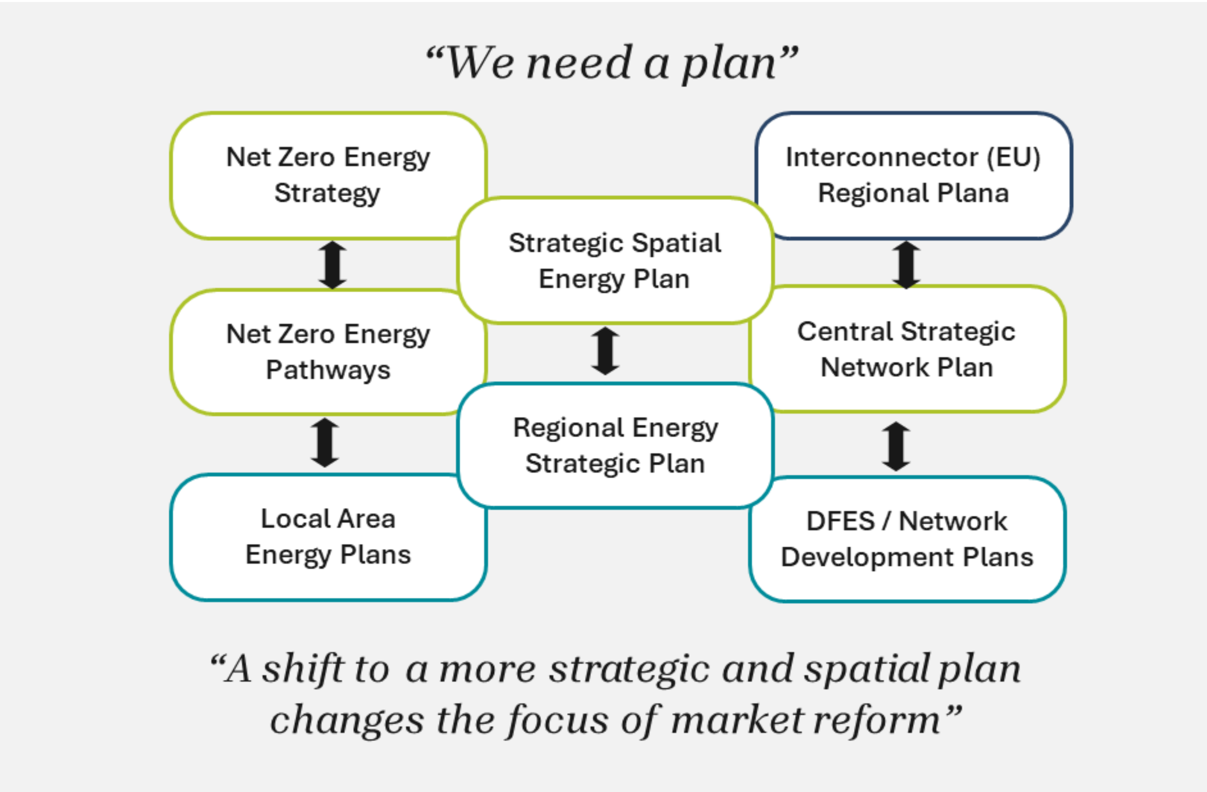

Figure 11. A new strategic planning landscape is emerging.

One area of consensus across industry stakeholders engaging in REMA is that GB needs an overarching net zero energy transition plan. Various targets have been set, but no whole-system plan for net zero energy delivery – and no overall spatial plan at either a national or regional level – has been established. There have been target capacities, milestone dates and 'sector deals' for some technologies, notably offshore wind, and to a lesser extent electric vehicles and heat pumps. Some regions have gone further than others – Scotland and Wales, for example, have begun to create their own net zero strategies. However, it is still the case that GB does not have an integrated[52] plan to achieve its medium and long-term decarbonisation and energy security targets, and so markets, policymakers, infrastructure providers and investors are still planning against very broad-brush scenario outcomes.

This has begun to change, and over the last 18 months initiatives have been launched that would, if delivered, form the basis of a new integrated approach to both energy and energy infrastructure planning.

At a national level, these include:

- A **Strategic Spatial Energy Plan (SSEP)** which could have a very significant influence on energy planning and would go a long way to provide strong locational signals for the electricity system, including generators and flexibility providers, and for network investment.
- Changing the basis of the ESO's **Future Energy Scenarios (FES**) from envelope[53] scenarios to become a net zero **'pathway'** with sensitivities, which, aligned with the SSEP, will give more of a direct steer for network planners and developers as to the future energy mix.
- A **Central Strategic Network Plan (CSNP)** which, building on the two rounds of holistic network design[54] and the future net zero (FES) pathways being developed by the ESO, should set out a long-term plan for onshore and offshore transmission grid investment.

At a regional and local level, new planning initiatives include:

- A new **Regional Energy System Planner (RESP)**[55] function that will be overseen by a new regional governance board (discussed in the Regen report Road to RESP: Unlocking Local Ambition May 2024). The RESPs are expected to be responsible for regional energy planning, including setting out a whole-system energy pathway that is aligned with the region's decarbonisation and growth ambitions and national energy strategic plans and pathways. The RESP, working with distribution networks[56] and other key stakeholders, could enable better local governance and decision making to support accelerated strategic investment and to give stronger locational signals in planning.
- **Local Area Energy Plans (LAEPs) and Local Heat and Energy Efficiency Strategies (LHEES)** that will enable local authorities to develop their own local energy plans or which would feed into the RESPs and development plans for distribution networks, heat networks, EV chargers and other local energy infrastructure.

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[52] Integrated – a joined-up spatial and temporal plan for the delivery of UK's net zero and energy security strategy including energy system architecture, generation and storage, flexibility, interconnectors and grid infrastructure. Ideally also with a supply chain and resource plan to back this up.
[53] 'Envelope' – scenarios that test the outer envelope of what could be a viable outcome rather than the most likely or preferred or optimised pathway.
[54] Two rounds of HND Pathway to 2030 and Beyond 2030.
[55] See Ofgem summary of RESP role and ESO summary.
[56] For collaboration between RESPs and DNOs see Regen/ENA report RESP Recommendations from the ENA Distribution Network Operator group.

Theme A: Summary reform agenda

Progressive market reform agenda	
A) Integrated strategic and spatial energy planning	
A1	Follow through with plans to develop a **Strategic Spatial Energy Plan** by end of 2025 with an appropriate level of detail and granularity to guide, but not restrict, market investment. Ensure that the SSEP has weight within the wider panning system and is aligned with industrial and regional growth plans.
A2	Continue to evolve the **Future Energy Scenarios (FES)** into a more focused set of net zero pathways with an optimised 'preferred' or lead pathway to be used by the CSNP.
A3	Complete the **Central Strategic Network Plan** and ensure that it is a genuinely holistic plan for onshore and offshore transmission infrastructure and interconnectors. **Ensure that the CSNP is aligned with national pathways and the SSEP** and can therefore provide the basis for system and market reforms.
A4	**Follow through and extend plans to reform the UK planning approval system** to enable rapid investment in both generation capacity and grid capacity. This is the single most important agenda item to achieve net zero.
A5	Develop a new **GB interconnector strategy** to ensure closer alignment between interconnector investment and GB net zero energy strategic plans. Work with EU partners to ensure that the GB interconnector strategy and plans are aligned with the EU's Offshore Network Development Plans.
A6	Implement the recommendations of the **Electricity Infrastructure Commissioner** to halve the time taken to deliver network investment, including reform to planning and the acceleration of network investment approval.
A7	Ensure that distribution network planning and investment is aligned with **Regional Energy System Strategy and local energy plans.** Ensure that RESPs work with networks and regional partners to accelerate network investment, economic growth and the delivery of net zero.
A8	Couple net zero and infrastructure investment plans with an **industrial strategy, supply chain and resource plans** to ensure the UK has the technology, assets, infrastructure and human resource needed to deliver net zero investment, while creating investment, growth and jobs in the UK.
A9	Creating integrated plans for energy asset siting that **consider wider system and economic benefits,** including system resilience, diversity of supply and the creation of industrial clusters and value chains.

A.1 The market works better, and can deliver more investment and innovation, within a strategic framework

Some critics have suggested that GB could go from the absence of a plan to an overburdensome ‘leviathan’ of net zero planning that could inhibit the market. This is a risk that should be avoided, but, given the need to accelerate investment, a strategic planning framework that recognises regional and local priorities within a national energy strategy should provide the market with strong but appropriate investment signals.

The appropriate level of plan detail, and spatial granularity, may vary by technology.

- For large projects with significant lead times, such as major new demand centres (e.g. data centres, large-scale CCUS and hydrogen industrial clusters), large-scale generators (e.g. offshore wind, nuclear and tidal range), very long duration storage and interconnectors, it would make sense to plan in detail at a national and regional level.
- For smaller-scale technologies with shorter lead times – onshore wind, solar, battery storage, smaller hydrogen to power, EV chargers, etc – it would make more sense to plan at a broad scale within national plans and in more detail within the RESPs and LAEPs.

Strategic planning could also deliver greater system benefits. For example, in Regen’s 2022 study Go West!, we considered the wider system benefits that could be provided by having a diversified offshore wind portfolio with more balanced deployment between the east coast and west coast. The study results showed significant energy resilience and system benefits by taking advantage of the typical west-to-east weather systems experienced by the UK. The same diversification logic could be applied to a future interconnector strategy, energy storage and generation technologies.

Better planning can also lead to better economic and industrial strategy outcomes. For example, at a regional level, energy planning should be considering the creation of cross-vector energy and industrial clusters and value chains combining, for example, power generation, green hydrogen production, energy storage and industrial use. A progressive market reform agenda would work towards a higher level of local and regional energy devolution for energy planning, supply and ownership.

The plans for RESPs, an SSEP and a CSNP are positive, but there is more work to do to deliver these initiatives and ensure that they are effective. There are also a number of gaps within the planning framework, including the consideration of interconnectors and the need for cross-border strategic planning with EU neighbours. Going further, as national and regional governments begin to think about what energy assets are needed and their location, it would make sense to consider the wider system and economic benefits that optimal asset siting can provide.

Key planning policies that still need to be developed include:

- **The terms of reference for the SSEP have not yet been published**. This needs to clearly set out the scope and granularity of the SSEP and its governance arrangements at a national and regional level. The SSEP must include interconnectors. It also needs to strike a balance between system optimisation and what is realistic in terms of wider planning constraints, development potential and investment. There is no point having an SSEP that's optimised for the grid network or system operation but puts assets in a place where they will never be built.
- **There is an urgency to ensure that grid investment planning within the CSNP is aligned with the strategic plan and then delivered on time.**[57] Many of the constraint and operational costs that have been modelled as market inefficiencies are in fact the result of an assumed misalignment between scenarios for deployment of low-carbon generation and network investment. Given that it takes a decade or more to deliver an offshore wind farm, interconnector or a nuclear power station, there is an opportunity to better align infrastructure investment, and thereby reduce the modelled constraint costs.
- A key missing component is a **national strategy for interconnectors,** which must be developed in conjunction with a wider cross-border European regional interconnector strategy. That means working in close collaboration with our European partners.
- **Linking energy plans with wider industrial strategy, skills and supply chain development, regional economic development and growth strategies is critical.** This also has implications for revenue support schemes like the CfD.
- **The status of energy plans in the wider planning process needs to be established**. It is expected that the SSEP – if adopted by ministers – would have weight within national and devolved government planning policy framework. The SSEP should – at least – guide other agencies such as the Crown Estate and nuclear authorities with regards to project siting and leasing. The status of the RESP and LAEPs within local planning guidance is unclear, but it is presumed that these plans would have some weight to guide planning applications.

The development of integrated whole-system plans that have support across national and regional stakeholders, have weight within planning, land use and lease awards and lead to accelerated network investment would go a long way to providing the locational signals that have been missing in the current market, as well as speeding up planning decisions and adding to investor confidence.

Under such a system, the role of electricity markets has the potential to change fundamentally. Rather than being *the* core tool for driving locational decision making, markets would need to work to support delivery of a plan that has already defined the broad locations for core

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[57] For a further discussion on strategic plans and grid infrastructure delivery see Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations.

technologies. In such a future it will be important that markets don’t work against delivery of the plan. For example, locational wholesale pricing (nodal or zonal) or unduly strong and misaligned locational network charges would have the potential to work against the delivery of a strategic plan that placed significant generation capacity towards the edges of the scheme.

It is unlikely, however, that strategic and regional plans would fully replace the need for locational signals for investment, especially for smaller-scale projects that have more flexibility in terms of their siting decisions. It is therefore important that other locational signals, such as network charging and connection queue management, are aligned with the plan. This is discussed further in Theme B.

Having a plan also has implications for the targeting of revenue support schemes like the CfD and CM, and should also have implications for the future management of grid connection queues and network charging.

Theme B

Sending the right locational signals

It has been argued that GB needs more and sharper locational signals to encourage developers of energy projects to locate in areas with grid capacity, thereby reducing the occurrence of constraints and future network costs. However, in Regen's insight paper Improving Locational Signals in the GB Electricity Market, we argued that, in reality, generators already receive a large number of locational signals, some of which are extremely 'sharp'. While some, such as transmission network charges (TNUoS), are financial, others are not related to price but might impact on timescales or likelihood of getting a positive decision on planning or a grid connection.

Current signals include those coming from the planning system, land use and leasing, TNUoS, distribution network connection costs and, especially at the moment, the long connection delays and connection queue. As a result, developers of generation projects are absolutely focused on finding parts of the network with capacity and where they can connect within the shortest timeframe and lowest cost. This challenges the basic modelling assumption that asset location is blind to network capacity and costs unless there is a market price signal.

If anything, the signals being sent may be too sharp, particularly when non-financial effects are included. It is still impossible to develop wind projects in England due to the planning risk,[58] delays in excess of 5-10 years for new project connections have become a common feature of the connection queue, TNUoS charge locational differentials between Scotland and England have widened and, as Figure 12 shows, are projected by the ESO to increase further up to £16 per MWh over the next five years.

Anecdotal evidence suggests that TNUoS charges are already slowing the development of onshore wind in Scotland and will likely result in higher CfD strike price rates for future projects. It has been suggested that this has already happened in allocation round 5, which happened to produce a high success rate for onshore wind (in part because of non-participation by offshore wind projects).[59]

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[58] See Regen 2024 Local Planning for Renewables 5 Key Policy Challenges.
[59] Onshore wind achieved over 1.4 GW of CfD projects – See CfD Round 5 results.

Theme B: Summary of reform agenda

Progressive market reform agenda	
B) Sending the right locational signals	
B1	**Ensuring that both financial and non-financial locational signals are aligned with the strategy and spatial energy plan** at a national and regional level. **Aligning network infrastructure planning and delivery** with the regional and national energy plans – and making it clear to developers where and when capacity will be available.
B2	**Directly identifying areas for project development** for core technologies (e.g. offshore wind and nuclear) and ensuring that **planning processes and decisions are consistently weighted** towards national and regional energy plans – so it is clear to developers and planners where projects will be supported.
B3	**Managing connection agreements and the connection queue** so that it is aligned with the energy and infrastructure delivery plan. This might include allowing earlier connection for projects on a time-limited **non-firm connection** basis.
B4	**Ensuring that both up-front connection charges (mainly on distribution networks) and forward network charges are aligned with the SSEP and RESP.** This does not necessarily mean setting higher or sharper charges, but does mean that charge structures attract investment where and when it is needed. Network charges may need to be more granular than at present and will need to be more forward-looking for locational elements.
B5	**Enable distribution-connected customers to work with networks to optimise and share available network capacity and collaborate on connection costs**. For example through grid collaboration, cluster and co-location development, active network management and non-firm connections.
B6	**Enhance transparency and effectiveness of signals for storage and flexibility providers, through open data and procurement processes.**
B7	**Consider whether the Balancing Mechanism and new markets like the Balancing Reserve should be made explicitly locational**. At present the control room operates the BM along zonal boundaries, but this is not explicit in the system price or settlement.
B8	**Ensure that locational signals also consider wider system resilience and diversity of supply.** For example, a key consideration for long duration storage is to spread these assets across a variety of locations that are aligned with network capacity, generation, demand centres and interconnectors. Diversity of location, and technology, is important to maintain overall system resilience and energy security.
B9	**Reform network charging for demand customers.** However, this needs to include consideration of the fairness and energy justice issues of charge differentials. Focus reforms on energy-intensive users and those sources of demand that may be more responsive to locational signals.
B10	**Enable consumers to access local energy supply**, for example, community energy schemes, Local Energy Clubs, long-term PPAs, regional generation tariffs and targeted green power pools or collaborative sleeved PPAs.

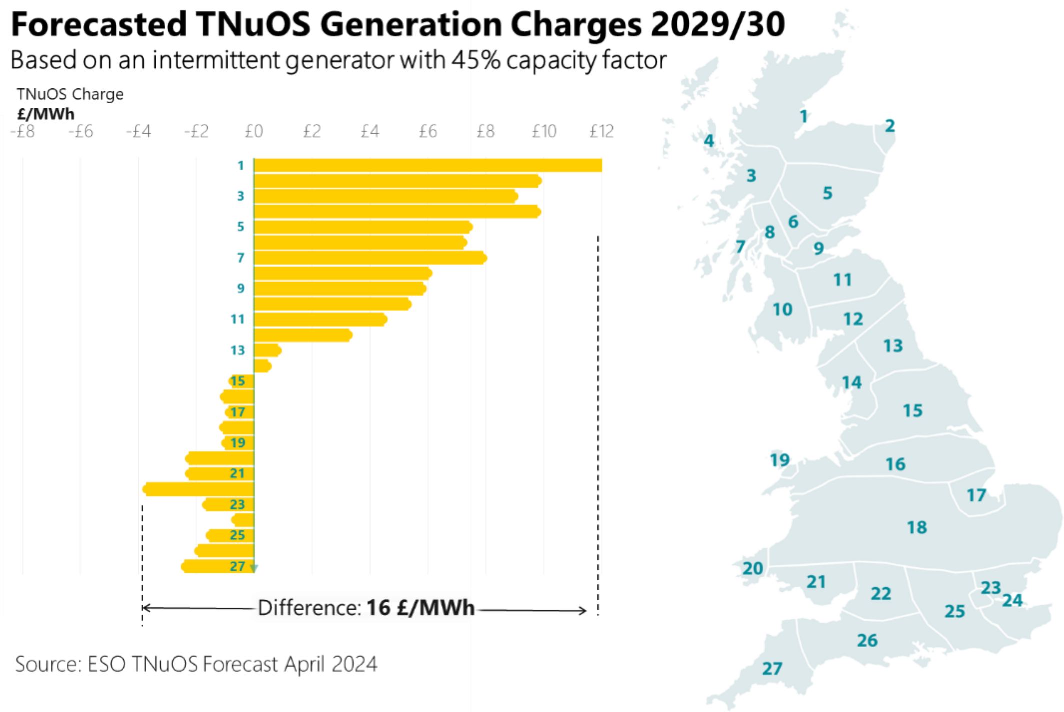

Figure 12. Forecasted TNUoS Generation Charges in 2028/29 for renewable generation.

B.1 Aligning locational signals with the strategic plan

The challenge for policymakers is not necessarily to make locational signals sharper if this merely increases risk and cost, but to ensure that locational signals are aligned with the overall net zero energy strategy, and that they will lead to positive decisions to invest in the right place, rather than act as a deterrent to investment overall.

As discussed in Theme A, a prerequisite for successful locational signals is to have a clear strategy and spatial energy plan so that policymakers can understand what locational outcome the signals are trying to achieve. It also means moving beyond a reactive ‘connect and manage’ approach, to proactive management of connections and the connection queue – a shift that is already happening. This overall approach and need for alignment is illustrated in **Figure 13**.

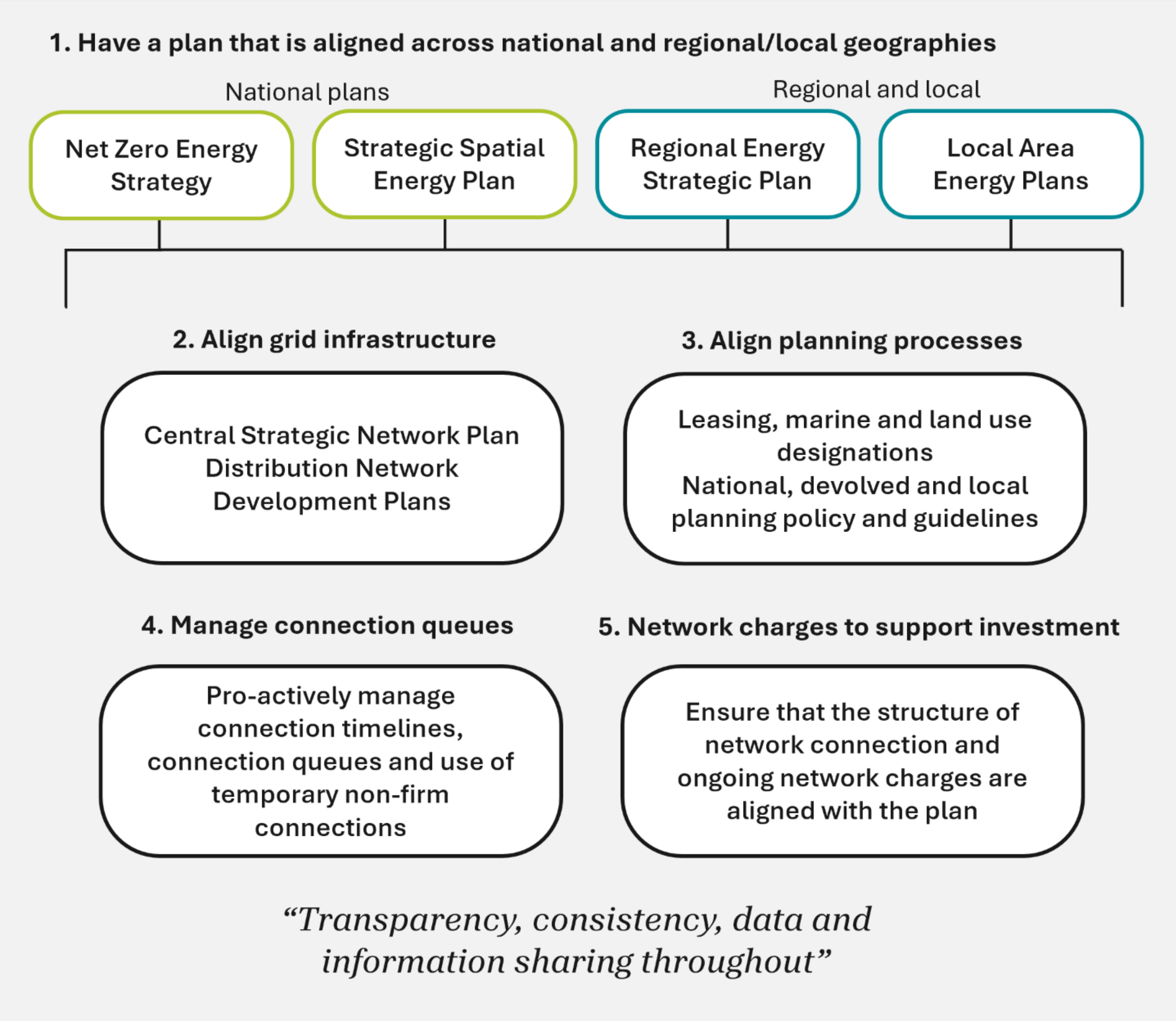

Figure 13. The plan should inform and dictate locational signals through infrastructure, planning, connections and network charges.

Within a programme of progressive market reform this can be achieved by:

1. Setting a clear SSEP at a national and regional level.
2. **Aligning network infrastructure planning and delivery** with the regional and national energy plans – and making it clear to developers (through forecast and data transparency) where and when capacity will be available.
3. **Directly identifying areas for project development** (e.g. offshore wind and nuclear) and/or ensuring that **planning processes and decisions are consistently weighted** towards national and regional energy plans – so it is clear to developers and planners where projects will be supported, and where they won't. For example, see Welsh TAN areas in Figure 14.

4. **Managing connection agreements and the connection queue** so that it is aligned with the energy and infrastructure delivery plan. This might include allowing earlier connection for projects on a time-limited, non-firm connection basis. (Section B.1.2)
5. **Ensuring that both up-front connection charges (mainly on distribution networks) and forward network charges are aligned with the relevant SSEP and RESP.** This does not necessarily mean setting higher or sharper charges, but does mean that charge structures attract investment where and when it is needed. Network charges may need to be more granular than at present and will need to be more forward-looking for locational elements.

Signals only work if they are clearly visible and dependable, so that developers are no longer trying to play battleships with planners and networks to find the right location. That means publishing forward plans and data, including network constraint maps and forward connection charges. It also requires clear and consistent processes, especially in relation to planning policies and network charges.

Connection reform[60] is now a major area of work for the ESO, TOs, DNOs and Ofgem. Changes in how we manage the connection queue will have a significant impact for developers and, if successful, would imply a far more engaged and proactive process. This is another step away from the previous 'connect and manage' approach and needs to be considered alongside the REMA reforms. Connection reform could significantly reduce the need to have additional locational signals, especially on the distribution network.

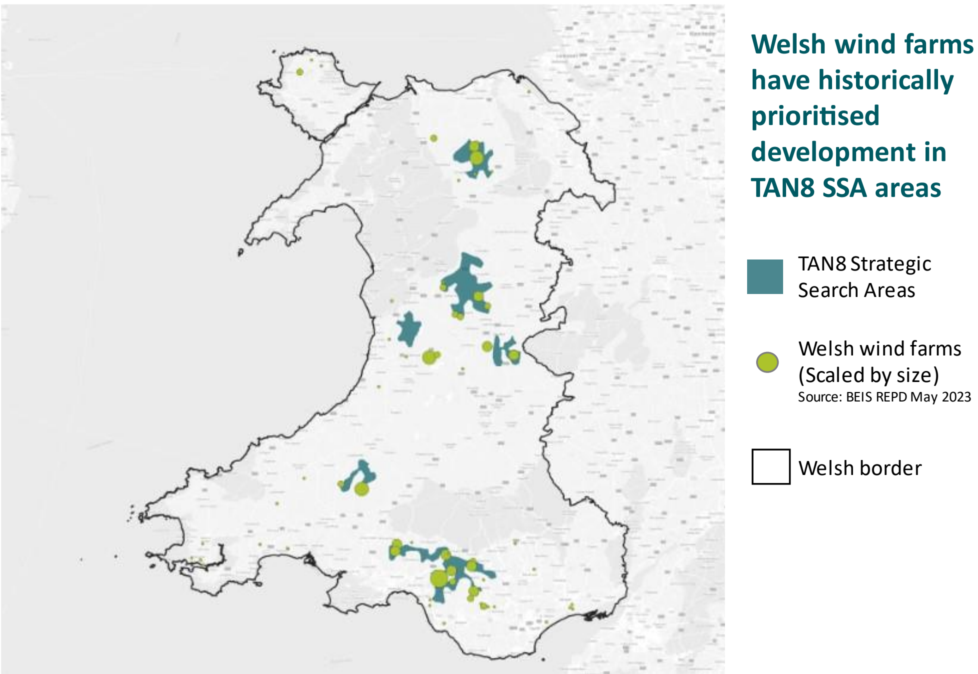

Figure 14. An example of proactive planning – use of renewable generation 'Strategic Search Areas' in Wales, which have significant weight in planning decisions.

[60] Connection Reform see ESO Reform Page and Proposals.

B.1.1 Reform of transmission network charging (TNUoS)

TNUoS is already sending very strong and largely negative locational signals for investment. TNUoS signals are negative in the sense that developers report that they are more likely to respond to higher forecast charges in the North, than lower or negative charges in the South. In part, this is normal risk aversion, but also reflects investor doubts about whether TNUoS forecasts are reliable, and how likely they are to be subject to regulatory or policy change.

To be effective, industry stakeholders have said that the network charge locational signal needs to be forward looking (5-10 years at least), forecastable and dependable. If not, the signal is likely to be negative only, increasing risk and cost in some areas, but not sending a positive signal for investment in others. The same investor concern applies, potentially even more strongly, to LMP-type signals.

TNUoS signals may be having a positive effect for some technologies that are more amenable to cost signals, but it is difficult to measure this impact if it is masked by other locational factors. Lower TNUoS charges are potentially encouraging large-scale solar PV to locate in southern England and developers are also responding to higher land prices, land-use designations and planning risk in this region[61] and therefore the Midlands have become a prime location for very large-scale solar. This is a good example of how a price signal may add cost but not produce the expected outcome if it is working against other, more potent, signals.

Balancing cost reflectivity with the appropriate strategic signal

The basis of TNUoS charges has been on cost recovery, and, therefore, the key design basis of the charge has been to accurately reflect costs. Cost reflectivity could mean different things but, in general, it may be considered as a means to:

1. **Recover the capital cost** (depreciation and return on asset value) over time of network investment.
2. **Recover the operating costs** of transmission assets including O&M and losses. Operating costs, including losses, will vary by location and especially transmission distance from generation to demand.

The problem with a purely cost-reflective approach, in the context of achieving a strategic goal such as the government's clean power mission, is that it can send locational signals which would run contrary to the energy and infrastructure strategic plan. For example, if the spatially optimised energy plan (SSEP) aim is to increase generation capacity in Scotland, or the south-west of England, and that will require a significant infrastructure upgrade and, therefore, capital costs – a predominantly cost-reflective TNUoS charge would then send a high cost signal to avoid building new generation in Scotland or the south west of England. In extremis, GB could end up building grid capacity and then send perverse locational signals that would dissuade

[61] For the same reason it is doubtful that an LMP-based price signal would actually result in as much PV capacity in southern England as has been modelled.

generators from using it. Right now, the large TNUoS charge differentials in Scotland are at risk of doing just that.

One way around this problem is to counteract the locational signal by providing higher levels of subsidy – CfD strike prices,[62] or CM payments – but this can then create infra-marginal profits for those generators that don't face such high locational costs. Alternatively, subsidies themselves could become more locational to negate network charge signals, but it all then becomes a bit pointless. Regen has called this the 'locational signal paradox'. In theory, it makes economic sense to send a negative cost signal to tell developers not to build in areas without grid capacity, but once a decision is made to build grid capacity in line with the strategic energy plan, the negative cost signal makes no sense and should be flipped. The same issues occur on the demand side with any new development areas, such as industrial zones and housing.

The network charge, therefore, must balance cost recovery and reflectivity, with the need to encourage development in areas that have been earmarked for deployment and grid capacity expansion, with sufficient time for developers to respond to the signals and align their project development decisions. This reinforces the point already made about the need to align locational signals and network investment with the strategic and spatial energy plan.

One approach would be to have a different treatment for capital and operating cost recovery.

- Capital costs, it could be argued, are to do with capacity expansion and should be aligned with the strategic energy plan and the delivery of net zero. If that is true, it could then be argued that a greater portion of these costs should be socialised – as net zero and energy security is a common societal goal. Capital costs are also sunk costs which, once committed, cease to have a locational relevance except to encourage the utilisation of the asset.
- Differences in operating costs, including losses, are more to do with location and transmission distance, miles of cable, etc, and, as such, could continue to send a meaningful locational signal.

Therefore, the design for a rebalanced TNUoS should focus locational signals for generation on the recovery of operating costs and less on the capital cost recovery.

An alternative means to convey strategic signals

An alternative reform proposal which has been proposed by Scottish Power, called OPTiC,[63] would recalculate forward TNUoS charges using an algorithm based on a forward forecast of future network constraints using an LMP-type pricing model.

[62] Commentators have suggested that winning onshore wind CfD bids in allocation round 5 (a round in which onshore wind did well) were higher than they might have been to compensate for higher TNUoS charges.

[63] Scottish Power, 2024. Beyond the OpTICs: a network charging solution for the future.

OPTIC would not require locational signals in the wholesale market price, but would use the same LMP logic to calculate future constraint costs, which could be used to provide a weighting for a portion of TNUoS recovered costs. Since the OPTIC model would be forward looking and based on forecasts of future constraints, it would (in theory) not penalise generators for locating in areas that may have limited capacity today but have been earmarked for capacity expansion in the strategic plan. On the other hand, generators would be penalised if they located in areas that will see rising constraints and are not planned for future grid capacity expansion.

The OPTIC price signal would be more reliable than a wholesale LMP price signal as it would be calculated by the system operator/regulator and could be locked into network charges on a long-term basis, rather than sent as the outcome of a hard-to-forecast and volatile zonal or nodal price. The OPTIC approach would need to be refined and tested, but it is the type of approach that should be further explored in a progressive market reform programme.

B.1.2 Allowing the use of non-firm connection agreements

One option under consideration by the REMA team and Ofgem is whether non-firm connection agreements could be offered as an option for transmission-connected assets.

Non-firm connections are already an option for distribution-connected assets and are normally associated with Active Network Management (ANM) schemes and Constraint Management Zones (CMZs). Allowing transmission-connected assets the option of a non-firm connection would bring the two networks' voltage tiers into closer alignment.

Regen has previously studied the benefits of non-firm connections as part of a study looking at the role of ANM schemes. An economic evaluation of the Active Network Management scheme at the Dunbar GSP concluded that non-firm connections could offer a developer an important opportunity to build projects more quickly – for example, ahead of network upgrades – but that there needed to be clarity about the purpose, extent and duration of the non-firm connection.

The primary purpose of a non-firm connection offer is to allow customers earlier access to a grid connection, provided the customer is willing to accept some degree of connection constraint risk. Constraints can be time-period based, capacity based or, ideally, part of an ANM scheme whereby generation is only constrained based on monitored thermal or voltage constraints and after other options (such as flexibility) have been exhausted.

For this to be fair, and also investable for the customer/developer, a number of conditions should be met:

1. **The option to accept a non-firm connection is a choice for the customer**, usually in order to get an earlier connection date or a lower connection charge.
2. **The duration of the non-firm connection should be time-limited** and will normally transfer to a full firm connection at a future point in time, usually after completion of a network upgrade or flexibility solution.

3. **The level of constraint is expected to be infrequent** or, at least, acceptable to the customer.
4. **The occurrence of the constraint should be forecastable** and/or limited under the terms of the connection agreement.
5. **The network operator must have some incentive** to use tools and options to try and limit the constraint.
6. **Non-firmness should be limited to a specific network constraint** – usually proximate to the customer – not used as a means to provide free flexibility and balancing for broader constraint management and system balancing. In other words, non-firm customers should not be exploited or penalised into providing free balancing beyond the specific connection constraint. One way to do this would be to still allow non-firm connected customers to provide Bid prices in the BM to be turned down, for any purpose outside the conditions of their connection agreement.

In the context of sending locational signals, the offer of a non-firm connection is not itself a locational signal, although identifying constraint management zones may be useful as a guide to developers, but is a means to allow more proactive connection queue management and to enable pipeline projects to come online earlier than they would otherwise. As with other areas of connection queue management, full transparency is essential to avoid unfair connection arrangements.

B.2 Locational signals for distribution-connected generators

Distribution-connected generators do not face as sharp locational investment signals within distribution network charging (DUoS) compared to transmission connections. DUoS charges do vary by distribution licence area, but have less of a locational differential.

Ofgem has been looking at the structure of DUoS, and whether charges could be made more locational and more granular, for several years. In 2023, Ofgem decided to separate out locational network charging DUoS reform under the Access Significant Code Review (SCR), in order to implement changes to the connection charges scheme, and to relaunch a separate Distribution Charges Significant Code Review.[64]

Regen, and the industry, have continued to engage in the DUoS reform process, but there remains some doubt about whether DUoS is the right scheme to provide granular investment locational signals, and what the purpose of those signals would be, because:

- Although they have been reduced as part of SCR, distribution-connected assets still face higher up-front connection charges, including a high price cap limit, which shifts

[64] Distribution Charges SCR.

more of the cost for network upgrades onto the developer. This forces the developer to look for low-cost connections.

- In many parts of GB, distribution-connected assets are also now subject to a transmission 'statement of works' process,[65] which means that they can also incur additional connection costs related to transmission level upgrades.
- Distribution-connected assets also face very long connection queue lead times.
- Distribution-connected assets can accept non-firm connections as part of ANM and CMZ schemes, and for solar PV and batteries this can be a workable option.

Given the locational signals already in place, developers seeking a distribution connection are already highly attuned to where there is network capacity and any options that will reduce connection costs. There is some doubt, therefore, whether an additional network charge locational signal for generation would be effective or necessary.

In addition, the objectives and purpose of more granular DUoS signals have not been defined. Any proposed reform is likely to be extremely complex and will have significant unintended consequences similar to the 'locational charge paradox' described above. As a result, very little work has been done to develop the DUoS case for change, or to assess what impact more granular charges would have.

A better approach, within a progressive market reform programme, would be to focus on opportunities for distribution-connected customers, to work with networks, to optimise and share available network capacity.

This could be done by:

- **Providing greater forward visibility** of network investment, constraints, capacity and flexibility requirements.
- **Looking again at grid-collaboration agreements** and the option for developers to collaborate to share and reduce network upgrade costs. See Regen's Grid Collaboration Scheme trial with NGED.
- **Supporting a strategic approach to unlock network capacity through co-investment and non-network solutions.** See, for example, Regen's work with SSEN and local partners on the Isle of Wight.
- **Measures to support and incentivise co-location** of generation, storage and demand assets.
- **Clustering of generation and cross-vector demand,** which could be enhanced through Local Area Energy Planning and Regional Energy Strategic Planning.
- **Supporting local energy supply options such as Energy Clubs, local generation tariffs and green power pools,** which can provide better options for supply/demand balancing and aggregated flexibility services.

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[65] A process whereby distribution connections may be subject to delay and additional costs caused by upstream transmission constraints – see for example NGED guidelines.

- **Further expansion of distribution flexibility services –** already widely used across the distribution networks, with 6.4 GW tendered and 4 GW contracted in 2023/24.[66]
- **Further expansion and use of ANM systems** and inter-trip services within CMZs.

In summary, there is a huge amount that could be done within a progressive market reform programme to reduce network costs, speed up connections and optimise network utilisation, before committing resource and time on uncertain DUoS locational reforms.

B.3 Locational signals for storage and flexibility

There are locational signals for storage and flexibility providers in the BM and other flexibility markets, through network charging and in the connection queue. A challenge for storage and flexibility providers is that, in a number of areas, the signals produced can be unclear, uncertain and, in some areas, contradictory.

There is a common understanding that the market should be encouraging storage to locate behind constraint boundaries (or co-located with a constrained asset) in order to utilise constrained renewable energy. This is indeed a potential role for storage and this is beginning to happen in some areas, especially in relation to co-location with solar PV.

Greater use of storage in the BM and for constraint management is encouraging storage to both increase its duration and to seek locations that offer the prospect of higher utilisation by the control room. This is predicted to increase the capacity of storage in Scotland and other constrained parts of the network.

It should be noted, however, that the commercial model to locate storage within a constrained area is still extremely challenging, because:

- The storage asset may itself be constrained from accessing other 'stacked' revenue streams.
- Within the current market arrangements, the alternative cost to turn down wind energy is in fact quite low, and will get lower if regulatory changes are made to remove lost subsidy payments from bid turn-down prices.[45] Although, arguably, lost wind costs should be higher to recognise carbon costs and wider economic value.
- Asset utilisation (cycle) rates for storage-plus-wind may be quite low given the duration of high/low wind periods compared to a daily solar PV cycle.
- There is an energy security and CM consideration if significant storage capacity is itself behind a network generation constraint.

[66] See ENA Open Networks report on the use of flexibility by distribution networks July 2024.

- Current operational processes within the ESO's National Control Centre tend to under-utilise ('skip') some technologies such as battery storage and do not use them for actions to reduce constraints.

Rather than attempt to push storage into a particular mode of operation which does not have a strong underlying business model, it would be better for policymakers to focus on increasing the transparency of commercial signals, widen market access and to address the contradictory signals sent by network connections and charges.

B.3.1 Locational signals for short-duration storage

In the case of smaller-scale battery storage there is a good argument that locational decisions should be commercially driven, based on their potential revenue yield versus cost of development and operation. For these storage assets it is important that:

- **Networks provide the right signals as to their future requirements for flexibility**. This is already beginning to happen on the distribution networks with the publication of forward-looking network constraint and flexibility requirements maps.[67] Transmission networks and the ESO should be providing the same forward forecasts for transmission constraints.

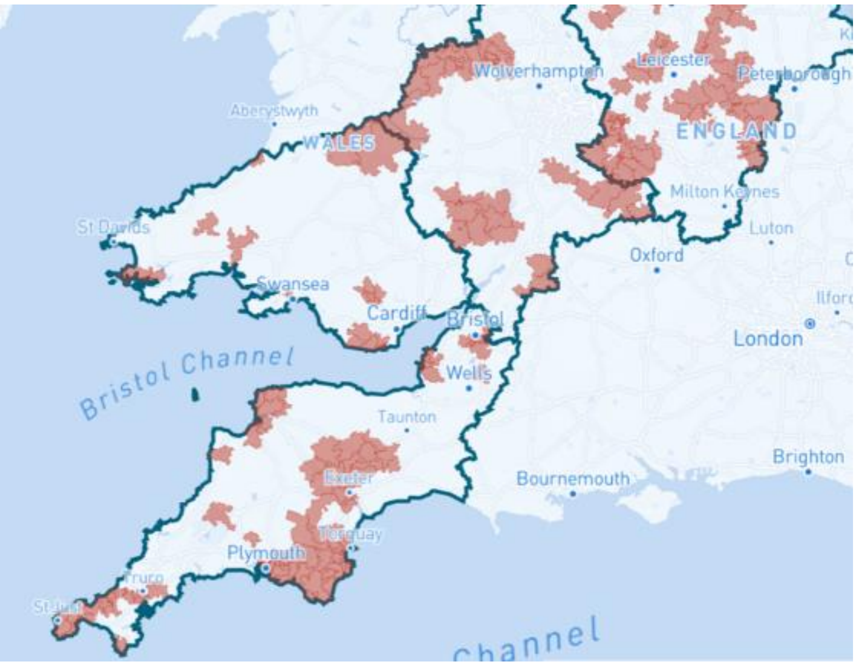

Figure 15: Example constraint/flexibility heat map. Source: National Grid Electricity Distribution

- **Network connection charges and queue management** can send very strong signals, but they should reflect the fact that, in many instances, storage assets will be working

[67] For an example see NGED's Distribution Network Options Assessment . Other networks publish similar analysis.

to alleviate and reduce system constraints. There is a good argument, therefore, that storage and co-location assets could be moved up the connection queue if they are able to work within a non-firm connection agreement. Work is already under way within the networks to better understand how storage will behave in the future and its load profile under different business models.

- **Network charges need to be reformed** to both recognise the role that storage plays, and that storage is unlikely to lead to additional network build since it will generally be charging and discharging in ways that are helpful to overall system balancing and peak load reduction.[68] There are several charging reviews and initiatives already in progress – one request from the industry would be to combine and harmonise these initiatives as far as possible.
- **Increasingly flexibility markets are producing much stronger locational signals.** The existence of an identified flexibility requirement with a procurement process is an obvious locational signal. Storage developers have pointed to the availability of a long-term contract from the ESO or distribution network operator to provide a local constraint management service as a strong stimulus for investment. The ESO's Thermal Constraint Collaboration project includes some long-term options and needs to move to implementation of solutions as soon as possible.
- **The utilisation of storage within the BM is also correlated with location.** It is not explicit within BM market prices, but it is well understood that the control room operates the BM along zonal boundaries. This can be seen in storage utilisation data, with some locations receiving very high dispatch rates compared to others. Already this is being picked up by the market and is beginning to influence asset locations.[69] Policymakers should consider whether the BM (and other markets such as the new Balancing Reserve)[70] should be made more explicitly locational in terms of the system price and recovery of balancing costs.

B.3.2 Locational signals for large-scale and long duration energy storage (LDES)

Locational signals for LDES can be augmented by market and commercial signals but, like other large-scale assets, need to be guided by the SSEP. Additionally, LDES projects will likely require a form of revenue support, currently expected to be based on a cap and floor model, which affords greater opportunity to impact the location and timing of project development.

Diversity of LDES location, and technology, is important to maintain overall system resilience and energy security. A key consideration for long duration storage is to spread these assets

[68] See Regen's response to Targeted Charging Review.
[69] For good data on the locational aspects of the BM see Modo analysis.
[70] See ESO Balancing Reserve.

across a variety of locations that are aligned with network capacity, generation, demand centres and interconnectors.

Depending on the LDES technology, location may also be determined by resource requirements e.g. topography and water supply for pumped hydro.

In addition to market locational signals from flexibility and balancing services, additional locational signals for LDES could be given via the process to award revenue support (e.g. cap and floor contracts) or via a locational element within the CM.

B.4 Locational signals for consumers

More work is needed to consider the extent to which different types of demand are exposed to locational signals that might influence their location.

At present, transmission-connected demand does receive some degree of locational signal via TNUoS charges, but this signal has been dampened through the introduction of a floor at £0 to the locational component of demand TNUoS. In part, the floor was introduced so as not to incentivise excess demand use during peak demand periods under the TRIAD scheme.[71] This means that, in practice, there is no positive locational TNUoS signal for demand in the northern half of GB. As the role of TRIADs changes, there could be a strong case to reconsider whether large-scale industrial demand should be receiving stronger network charge signals to locate in areas of high generation/low demand. This point is discussed further in Regen's paper Improving Locational Signals in the GB Electricity Market.

Regen has calculated that if the floor TNUoS charge of zero per MWh was removed, allowing demand customers in Scotland to receive a TNUoS credit, then the TNUoS differential between the far north and southern zones could be as wide as c. £6-£8 per MWh.

[71] Network charges are set during TRIAD periods – a negative TNUoS price (incentive to demand) would therefore encourage a customer to maximise their demand during the peak TRIAD demand period. This is a feature of the TRIAD scheme and could be addressed.

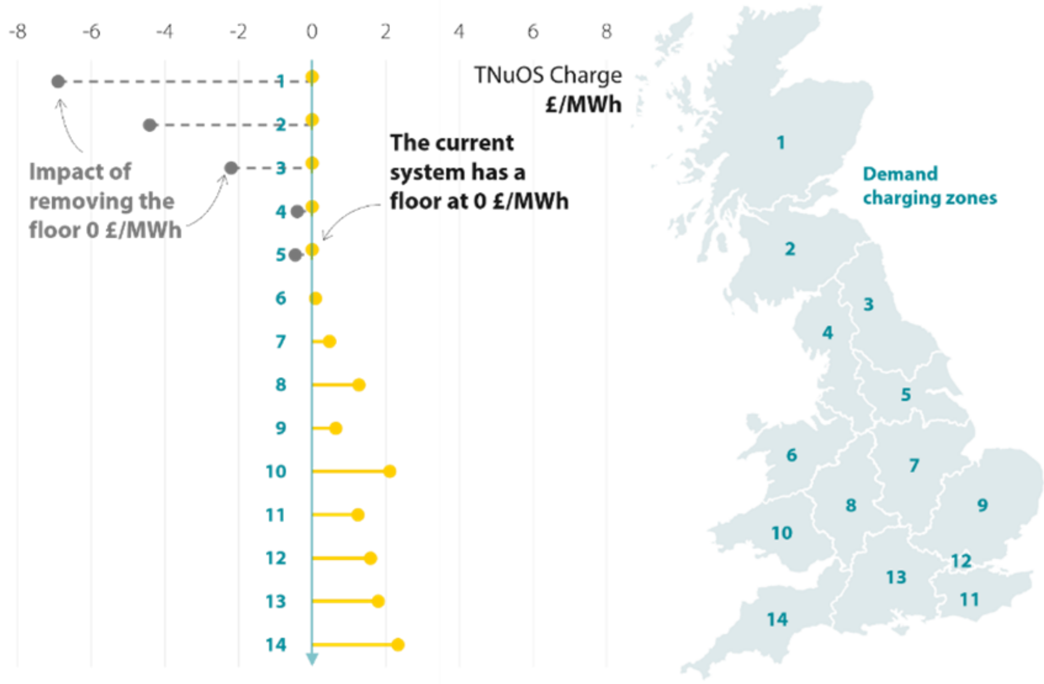

Figure 16. Demand TNUoS costs in £/MWh based on a 50% load factor against its TRIAD demand, showing the current system that includes a floor at zero and the impact of removing that floor. Source: ESO TNUoS Forecast Data, April 2023.

Adding locational granularity to distribution charges (DUoS) could also help to give better locational signals for demand siting. However, there is an important fairness and just transition issue to be addressed. Is it fair and appropriate to give very strong locational signals to householders and smaller business users based on system constraints or network costs when, for the most part, consumers are unlikely to be able to move or base their siting decisions on the price of energy?

However, there may be exceptions, and the progressive market reform agenda should include a review of network charges for energy-intensive industries and for those consumers, such as data centres and hydrogen electrolysers, whose choice of location may be more flexible and more heavily influenced by energy availability and cost. As well as network charging, this could be done, for example, as part of a regional industrial and clustering strategy, potentially enabled by regional and sector-based green power pools.

As discussed in Theme G, a more progressive approach for consumers would be to support local energy supply, for example, through community energy schemes, Local Energy Clubs, long-term PPAs, regional generation tariffs and targeted green power pools or collaborative sleeved PPAs. Consumers and local stakeholders have consistently said that their motivation to engage with the energy system would be enhanced not by a postcode lottery of network costs or locational price signals, but by being able to source and buy local energy.

Theme C

Operating and optimising a clean power system cost-effectively

A key tenet of progressive market reform is that operational and market efficiency should not be in conflict, and that reforms and enhancements to both are needed to ensure the best overall energy system outcome.

A review of the challenges of operating a high renewable energy system suggests that, while there is clearly a strong case for reform and for system operators to have greater visibility and control, there is not a clear case for radical market redesign options such as zonal pricing and centralised dispatch that would potentially restrict or corral the market. The REMA reform process has, in fact, highlighted a very large number of operational reforms that could be implemented within the existing national market arrangements. Taken together, these would constitute a very significant package of reforms which would address the operational challenges and could be implemented more quickly than more radical redesign options.

The progressive market reform agenda is based on a forward-looking reform programme in which both market and operations are enhanced through innovation, investment in digitalisation and operational capability, process redesign and new market structures.

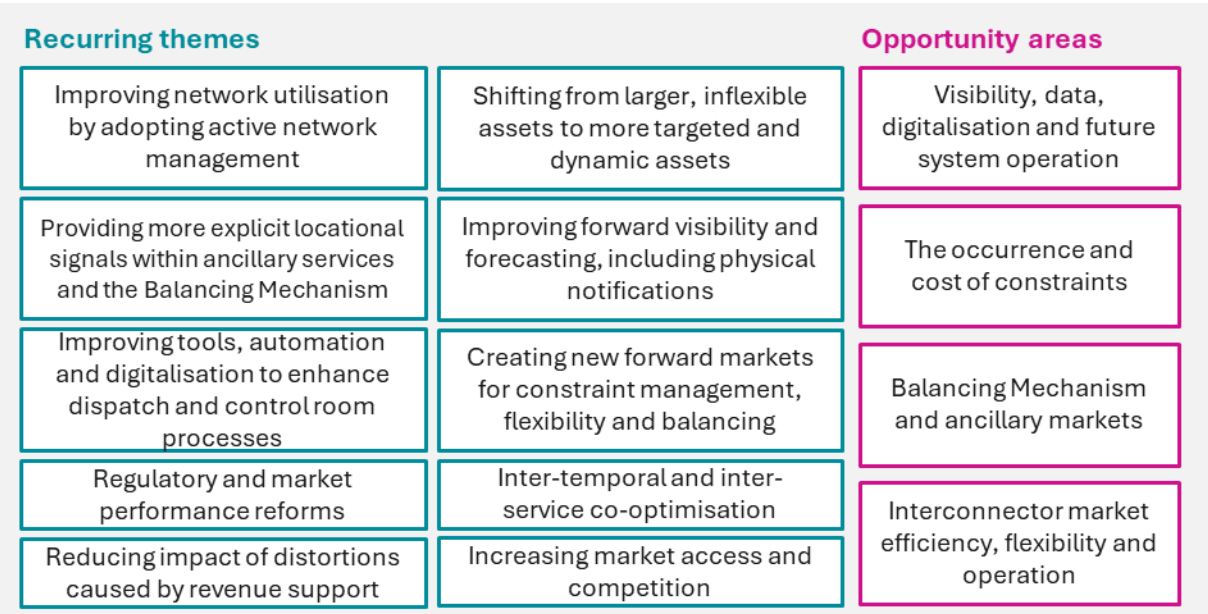

Figure 17. Recurring themes and opportunity areas for operational efficiency.

Theme C summary reform agenda

Progressive Reform Agenda	
C) Operating and optimising a low-carbon system cost-effectively	
C1	Update the Strategy and Policy Statement for Energy Policy in GB to reflect the UK's mission to achieve clean power, defined in terms of the carbon intensity of the grid in 2030 and 2035. The updated statement should also update the remit for Ofgem and the National Energy System Operator (NESO) as to their role in delivering the mission.
C2	Continue and accelerate the ESO's market road map and flexibility strategy, including reforms to the balancing mechanism and the and introduction of new constraint and flexibility markets
C3	Continue and accelerate investment in ESO despatch and control rooms functions with a focus on digitalisation, data transparency and visualisation, forecast capability and automation/AI.
C4	Run a joint industry collaboration project looking at intertemporal optimisation
C5	Review gate closure and settlement period decisions with the view to reduce both over the longer term
C6	Define new incentives and obligations for market participants to increase data access and visibility, forecast accuracy, physical notification accuracy.
C7	Task the ESO to produce an overall constraint management plan showing its updated constraint costs forecast and an overall action plan of how it is goi8ng to work with industry and markets to reduce the occurrence and cost of constraints
C8	Prevent current and future gaming and anti-competitive behaviour but increasing levels of data openness and transparency. Improve monitoring function and continue to challenge and sanction anti-competitive behaviour.
C9	Establish a taskforce/delivery team to review the strategy and operation of GB interconnectors, including IC planning and appraisal, IC operations and the tools needed by the NESO to manage IC flows.
C10	Link the UK's clean power mission with the review of the UK-EU Trade and cooperation agreement and put energy alignment and cooperation at the forefront of steps to achieve a closer UK-EU trading and security partnership. Develop closer integration with EU neighbouring markets with a view to enhance market coupling, coordination and co-investment across interconnectors and offshore infrastructure.
C11	Provide more detailed analysis on the deeming of CfD and its potential benefits, impact on future strike prices and any risks around liquidity and market distortions.
C12	Review the merits and impact of removing subsidy costs from BM bid and offer prices

C.1 Visibility, data, digitalisation and future system operation

It is clear from the REMA consultation and stakeholder engagement sessions that there is a strong case for reforming and investing in the GB wholesale market, ancillary markets, BM and system operation processes. This is especially true in areas such as data visibility, IT system integration, automation, use of AI, forecasting and digitalisation.

As discussed in Section 0, the move from 'the Pool' with centralised dispatch to a more liberalised bilateral trading arrangement following the NETA and BETTA reforms brought significant market efficiencies and price competition. However, while trading arrangements have evolved significantly over the past 20 years, operational arrangements have become imperfect and 'clunky'. Interconnectors are a good example where, especially since Brexit, market efficiency has been lost. This was less of an issue when GB only had 3-4 GW of interconnector capacity, but with over 10 GW, interconnectors now form a key part of the overall GB electricity supply and so their efficient running is critical.

C.1.1 Visibility, access to assets and forecasting

A key issue for transmission and distribution system operators and market participants is that the current market lacks transparency and/or access to data in key areas related to asset status, physical volumes, forecasts and trading activity. The issue of visibility has been highlighted by the ESO (supported by AFRY) as part of its dispatch and scheduling case for change analysis[72] and, more recently, during the June ESO Operational Transparency Forum.[73]

Examples of visibility and forecast issues include:

- **That more participants are connected to the distribution network** as 'embedded' generators or storage providers.[74] Some embedded assets are visible to the system operator and participate in the BM, but others do not.
- **Significant volumes of transactions occur during intraday balancing trading** and through bilateral trades, especially on days where there is greater price and volume volatility.
- **Negative price periods that are especially difficult to forecast** as generators (and traders) will continue to trade and arbitrage to find a buyer at a positive price in the intraday and cross-border markets.[75]

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[72] For a further discussion around market transparency see AFRY, GB Scheduling and Dispatch The Case for Change, 2024.
[73] For details on FPN accuracy and other operation challenges see Operational Transparency Form 5/6/24.
[74] Around 38 GW of capacity (7.5k projects over 1 MW) plus microgeneration is connected to the distribution networks. This includes 2.9 GW of storage, the majority (2/3rds) of which is battery storage.
[75] A good example of a loss of transparency event occurred during a negative price period on 29 December 2022, when three offshore wind farms that were expected to be offline for six to eight hours began generating after 45 minutes.

- **Final Physical Notifications (FPNs)** that are proving to be less accurate, especially for wind generation. As well as inaccurate FPNs, the ESO has reported poor operational metering and assets not delivering balancing volumes as bid/offered in the BM.[73]
- **Late changes to interconnector flows and scheduled volumes** within the intraday market.
- **Other complicating factors for the system operator**, including assets that deliberately put themselves in an imbalance position (known as NIV chasers) in order to exploit high or low system prices.

Some of the identified issues are the result of a more dynamic and agile market and are not necessarily a sign of market failure. For example, it is beneficial for generators and traders to continuingly adjust their trading position, and to try and find a market for 'excess' electricity during intraday trading or via interconnectors. Although it may be tempting to try to corral the market to reduce the challenges of system operation, this could ultimately reduce market efficiency and the ability of consumers to make best use of available low-cost and low-carbon energy.

As an example of corralling the market with unintended consequences, negative price rules – introduced to prevent the occurrence of negative price distortions caused by the CfD regime – may now be contributing to market volatility and volume movements when negative price thresholds are met.[76] This has resulted in instances of 'herd behaviour', when several generators are incentivised to ramp-up or ramp-down power output in response to a threshold price. For a potential solution see deeming CfD payments, as discussed in Section D.2

While dynamic free markets are beneficial, on the other hand, it is clearly inefficient to allow continued forecast and metering errors to occur. This is a clear area where market reform and enhancement is needed. There may also be a case to ensure that the system operator has access to trading data and to volume forecasts from most distribution-connected assets. This could be achieved by extending the requirement to submit physical notifications to more asset classes, based on the asset size or participation in certain markets, like the CM.

As more and better-quality metered data becomes available, the system operator will be able to improve its own forecast performance.

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[76] Several negative price rules have been introduced – including a 'six-hour rule' and a more recent absolute negative price rule – whereby generators do not receive a CfD payment during periods when day-ahead prices are negative.

C.1.2 Control room functions and operations

The ability of the control room to operate a very high renewable system has been one of the key goals for the ESO. Historically the control room has relied on large generation (mainly gas) assets, which are relatively easy to dispatch within the short time window between gate closure and delivery period. However, this is now proving to be costly and inefficient, especially during the recent energy crisis. Over the last five years, with initiatives like the Power Responsive[77] programme, there has been far greater impetus to widen ancillary and balancing market access, and to utilise more flexible assets including storage and demand response.

The National Control Centre of the of the Future will be far smarter and more digitalised and automated. This will better enable controllers to optimise the use of all balancing assets and target actions using the least cost solution.

Opportunities to improve operational efficiency include a number of initiatives that are already in progress, or could be delivered in a relatively short timeframe within a progressive market reform programme. These include:

- Steps to develop the 'control room of the future', which would be fully digitalised, highly automated and make use of the latest AI and digital twin technologies, such as Virtual Energy Systems.[78]

[77] The Power Responsive Programme is a stakeholder-led programme, facilitated by the ESO, to stimulate increased participation in different forms of flexible technology, such as Demand Side Response (DSR) and storage, which preceded and underpinned the ESO markets roadmap and flexibility strategy. See 2024 Annual Report for latest

[78] ESO, 2024. Virtual Energy System. ESO, 2024. Balancing programme.

- **Investing in new IT systems, processes and capabilities –** e.g. the Open Balancing Platform – to enable the control room to utilise a wider range of assets, to dispatch multiple assets and to reduce the 'skip rate', whereby more expensive assets are used because of limitations within the control room function.

- **Automation and data integration** that would enable the control room function to efficiently harness new forms of demand-side flexibility and coordinate system actions across energy vectors and transmission and distribution networks. It would also enable it to better optimise dispatch, using multiple assets across multiple time periods, and to co-optimise balancing and ancillary service provision.[79]
- **Improvements to access asset data including embedded generation and storage.** A good example here being the time limitation on the use of storage assets, due to the ESO not having access to storage state-of-charge data (30-minute rule).
- **Collaboration between transmission system operator and distribution system operators** to ensure alignment of system actions and optimisation across networks.
- **Greater system and operational integration** (coordination) with neighbouring energy systems in Ireland and the rest of Europe.

C.1.3 Intertemporal and co-optimisation challenges

The current BM design is based around the concept of a system price for balancing and optimisation within 30-minute settlement periods. In reality, the ESO needs to balance the system in real time and also needs to be able to optimise the redispatch and scheduling of assets that may have minimum runtimes of several hours. As well as power balancing, the ESO is also trying to manage several different operability factors, including frequency, reactive power, constraints and reserve.[80] The disconnect between the settlement time period in the BM and the reality of dispatch and operability means that:

> "The current dispatch mechanism does not facilitate effective optimisation of costs and unit constraints over time."
>
> "The lack of effective optimisation of costs and unit constraints over time means that: market players can face conflicting incentives with a lack of coordination between ESO actions and market scheduling decisions; there is potential for energy-limited and other flexible resources to be underutilised; and incentives for market participants to support system energy balance are dampened".
>
> – ***AFRY Case for Change: Scheduling and Dispatch 2024***

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[79] Inter-temporal dispatch optimisation across several settlement periods is currently a process and market challenge.
[80] For a good overview of operability factors see A Day in the Life of the Electricity System 2035 Regen and ESO 2023.

The AFRY Case for Change: Scheduling and Dispatch report provides a compelling case that the ESO requires new capabilities, tools and access to data in order to efficiently perform its system balancing and operability functions.

The case for change report identifies:

- The ability of the ESO to take advance decisions outside the immediate balancing window. This currently hampered by limited information.
- A greater need for ESO-instructed synchronisation generation and more energy limited units on the system (which has increased because of the scale of network congestion).
- The need for improved incentives on participants to provide accurate information and forecasts, and to behave in ways that support, and do not hinder, system operations.
- The ability to manage storage, demand-side response and other forms of flexibility over multiple time periods.

A report by Frontier Economics and LCP/Delta identifies a very similar set of issues and opportunities, including the vital importance of making best use of storage and flexibility.[81]

> "We understand that ESO currently considers the use of battery storage in a single period.[82] By considering the optimal use of storage (and other balancing sources) over multiple periods, ESO may be able to reduce overall system costs by using stored energy more efficiently." – **Frontier and LCP Delta**

While the papers by AFRY and LCP Delta/Frontier, plus the work being done by the ESO itself, make a compelling case for reform, innovation and enhancement, it is not obvious that a return to a central dispatch model is the necessary or only solution.

Based on Regen's engagement with energy storage asset owner/operators, including members of the Electricity Storage Network, there is a strong consensus against central dispatch in favour of asset operators retaining self-dispatch and the ability to optimise asset utilisation and revenue stacking. The progressive market reform agenda would focus resource on innovation and making significant improvements that build on the investment and work that is already in progress, especially around data and digitalisation.

[81] Frontier and LCP/Delta Analysis of Reform Options for Status Que Electricity Balancing Arrangements April 2024.

[82] National Grid ESO, Enhancing Energy Storage in the Balancing Mechanism.

C.1.4 Other operational reforms – settlement periods and gate closure

The progressive market reform agenda would include a shift to shorter settlement periods. A move to a 15-minute period is a reasonable starting point with the aim of a further shift to five-minute settlement periods in the foreseeable future.

The agenda would also include a review of the gate closure timing and the process for the submission of physical notifications. In the future, with improvements in data flows, forecast accuracy and digitalisation, it should be possible to reduce the gate closure period, and to move to real-time or rolling-volume physical notification updates.

C.2 Reducing the cost and occurrence of constraints

The rise in constraint management costs was a key driver for policymakers to look at radical market reforms such as LMP, and the red flags raised by the ESO that the market is not working.

In fact, although constraint volumes will clearly increase if GB does not build network capacity that is aligned with generation and interconnector deployment, the recent rise in constraint costs has been mainly caused by a very steep rise in wholesale prices over the energy crisis period and the continued reliance on large, and inflexible, gas-fired power stations.

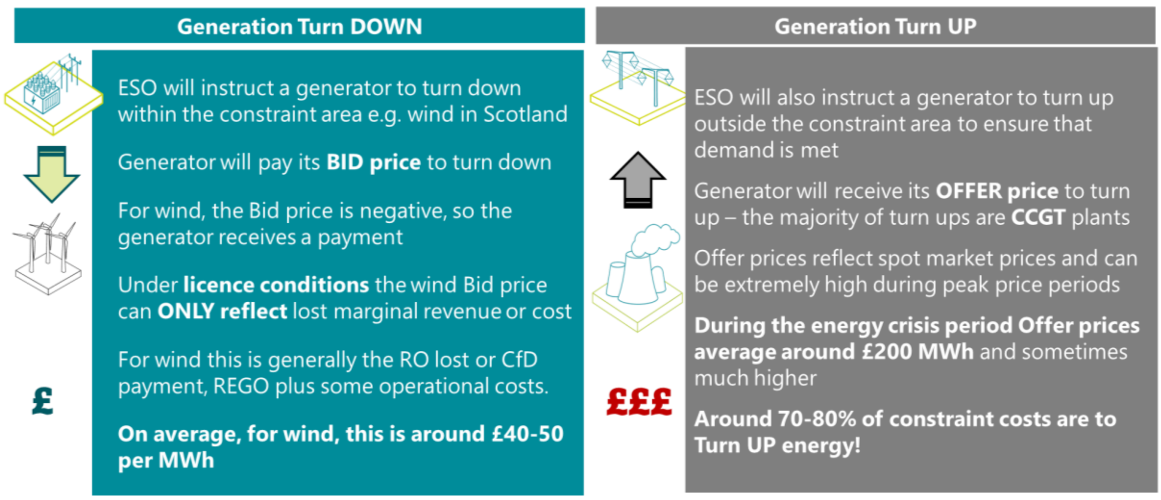

Figure 18. Constraint management costs are driven by constraint volume, and the cost to turn up (mainly CCGT) generation to replace constrained renewable generation.

Regen, along with other stakeholders examining constraint costs, has identified a number of reforms, process enhancements and market advancements capable of diminishing, though not entirely eradicating, the frequency of constraints and the expense of managing them.[83,84]

Several of these reforms are already in progress, either as part of innovation projects or within the constraint management and new markets initiatives being rolled out by the ESO.

Five reforms that would help reduce the occurrence of constraints:

1. The adoption of active network management principles and technologies, including, for example, greater use of constraint management inter-trip services.[85]
2. Improvements to forecasting and measures to improve and incentivise more accurate physical notifications.[86]
3. Grid 'booster' services which would provide very rapid battery turn-up services to enable the control room to better manage the impacts of variable generation.
4. Providing more explicit locational signals within the BM and ancillary service markets to encourage flexible plants to locate in areas where they can provide constraint management services.
5. Improving the function of the BM so that it creates a market for flexibility providers to bid for what would otherwise be constrained generation.[87]

The current ESO Thermal Constraints Collaboration Project has produced more than 30 responses.[88] Several of these, including enhanced inter-trip and grid booster ideas, are aiming to enhance the ability of the control room to increase and optimise grid capacity utilisation and manage variable generation without needing to turn down generation.

[83] Examples of Regen studies include Seven Solutions to reduce Constraint Management Costs and evidence given to the ESNZ Select Committee.
[84] See, for example, analysis by Dr Simon Gill: Exploring options for constraint management in the GB electricity system. Frontier Economics Reform options for electricity balancing arrangements in Great Britain.
[85] The current CMIS reported by the ESO has produced £80m in cost saving in its first 10 months of operation.
[86] ESO, 2023. Forecasting Stakeholder Working Group.
[87] Similar to the German Government proposed changes to balancing to promote a 'use don't curtail' principle.
[88] ESO, 2024. Thermal Constraints Collaboration Project.

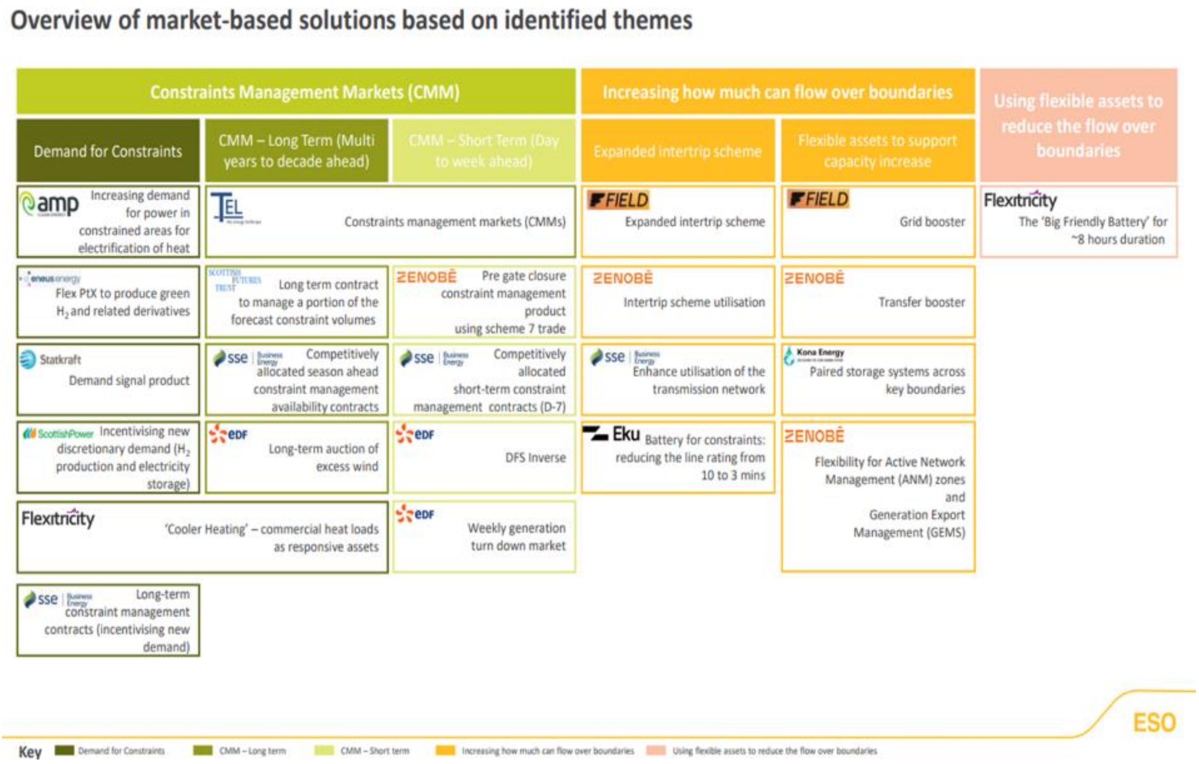

Figure 19. ESO Open Industry Project on Thermal Constraint Collaboration.

Some degree of constraint is inevitable, and even desirable, as it would not make economic sense to build a grid so large that this would never occur. In terms of overall economic efficiency, it is an important principle that solutions to minimise constraint cost, for example, by changing generation output, or calling upon other forms of the demand and storage flexibility are actioned in markets that are truly competitive and there is no gaming, manipulation or other forms of market power.

A current challenge for the system operator is that the bulk of constraint management actions are still taken through the BM post-gate closure,[89] at a time when control room functions are most under pressure, with inadequate IT and digital capability, predominantly using large and inflexible gas generation.[90] Enabling the ESO to take actions outside the gate closure window, for example through constraint and flexibility markets, would provide additional options and potentially increase competition with BM.

[89] Simon Gill Energy Landscape report for Scottish Renewables. Exploring options for constraint management in the GB electricity system: the potential for constraint management markets.
[90] Studies by LCP Delta, Regen and others suggest that CCGT plants still perform over 80% of balancing turn-up actions.

"This report suggests that we need to develop a much more sophisticated toolkit, built on a clearly defined objective to maximise and protect consumer value. As it transitions into the Future System Operator, this should provide National Grid ESO with a range of tools which can be used over timescales of hours, days, months and years to minimise consumer costs and, importantly, actively manage consumer risk." – **Dr Simon Gill, Energy Landscapes**

Seven reforms that could help reduce the cost of constraint management include:

1. Expanding access to the BM to storage assets, demand response and other smaller generation plants, to maintain a high degree of liquidity and price competition.
2. Enabling the use of smaller, more responsive and flexible, solutions in the BM that can provide constraint management services without creating 'bullwhip' effects.[91]
3. Investing in IT systems, processes and capabilities to enable the control room to utilise a wider range of assets to reduce the 'skip rate' whereby more expensive assets are used because of limitations within the control room.
4. Establishing new market solutions that will give the system operator the option to procure constraint management services ahead of gate including through forward trading, flexibility contracts and the creation of local constraint markets.
5. Continuing to monitor market behaviour and tighten up on rules around the Transmission Constraint Licence Conditions, physical notifications and withdrawal of service, generation estimates and exploitation of market power.
6. BM reforms and improvements, as discussed in Section C.3
7. Interconnector reforms, including allowing system operator-to-system operator countertrading and interconnectors to provide balancing services, as discussed in Section C.4 .

There are some great examples of reforms that are working and help reduce constraint costs. For example, the current Constraint Management Inter-trip Service (CMIS)[85] is reported to have saved £80m in its first 10 months of operation. The Open Balancing Platform and changes to the limitation of battery dispatch have increased battery utilisation in the BM.

A progressive market reform agenda should include an ESO-led action plan to reduce constraint costs and to prioritise investment and market development in this area.

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[91] 'Bullwhip effects' can be described as an overresponse to an market or system imbalance, in this example, caused by the need to run a CCGT plant for longer and at a higher power output than would be needed.

C.3 Balancing Mechanism and new flexibility markets – widening access with increased competition

Several of the proposed reforms to the BM have already been highlighted in the previous section on constraint management costs. These include widening participation in the BM to many more assets and flexibility providers and improvements to IT systems and processes to enable the control room to manage and dispatch assets more efficiently.

Since the start of 2024, the introduction of phase one of the Open Balancing Platform tool to allow multi-asset dispatch, and changes to the limitation on battery dispatch duration,[92] have made a significant impact. Modo Energy has estimated that these changes have coincided with a 100% increase in battery utilisation between December 2023 and April 2024.

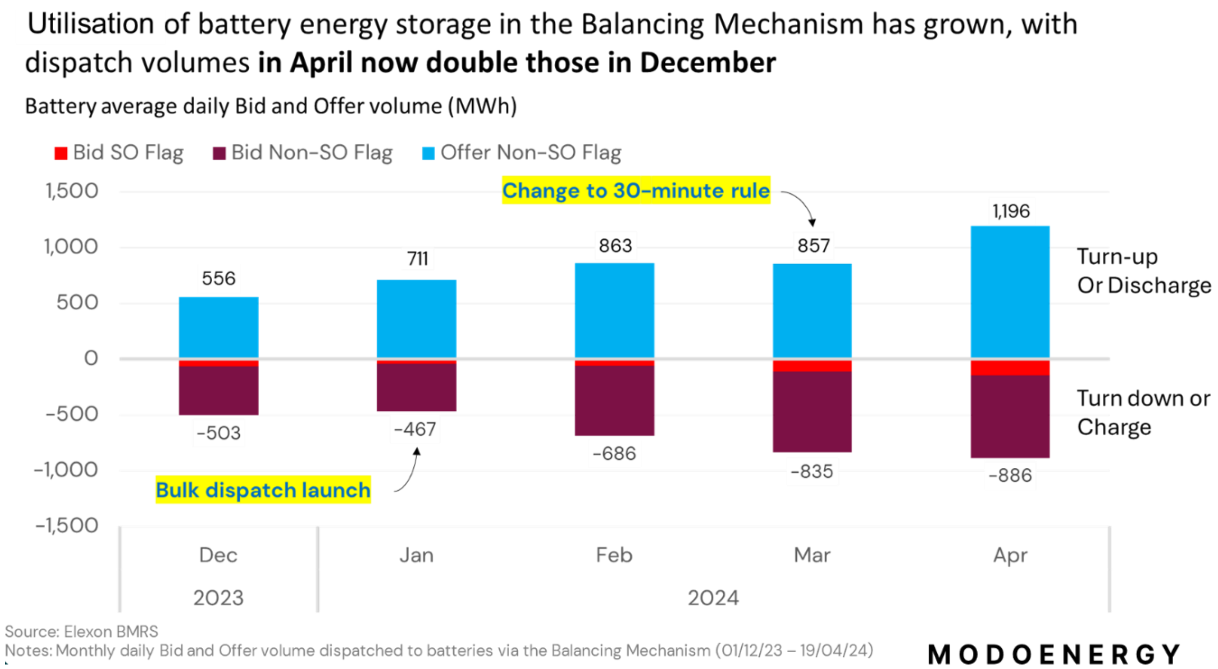

Figure 20. Changes to battery utilisation in the BM following the implementation of the Open Balancing Platform and changes to the 15-minute rule. Source: Modo Energy.

[92] Known as the '15-minute rule' caused by the lack of visibility of battery charge status to the control room.

C.3.1 Future enhancement of the BM function, market and processes

The improvements made to date could be seen as the start of a more ambitious programme of reform and investment to create an advanced BM operated by the 'control room of the future' which would be fully digitalised, highly automated and make use of the latest AI and digital twin technologies, such as Virtual Energy Systems.[93,94]

Such an advanced BM and control room function could efficiently harness new forms of demand side flexibility and coordinate system actions across energy vectors and transmission and distribution networks. It would also enable the control room to better optimise dispatch using multiple assets across multiple time periods and to co-optimise balancing and ancillary service provision.[95]

Other balancing reforms that have been highlighted include:

- Measures to increase access, liquidity and price competition, building on the introduction of the Open Balancing Platform.
- Changes to settlement periods and gate closure window.
- Changes to the use of BM parameters and bidding rules.
- The potential to include all CM participants within the BM.
- Introduction of more explicit locational signals within the BM and other ancillary services to support asset siting.
- Inter-temporal dispatch optimisation across several settlement periods.
- Improved forecast and Final Physical Notification (FPN) accuracy.
- Improved asset status visibility, for example, storage, smaller and embedded assets.
- Enabling interconnectors to provide balancing services.

C.3.2 Making best use of flexibility – new markets development

To stimulate and expand markets for storage, flexibility and demand side response the progressive market reform agenda would build on the market development roadmap and programme already established by Ofgem and the ESO.

The Power Responsive programme, established by the ESO in 2019, was set up with the objective to stimulate increased participation in the different forms of flexible technology such as demand-side response and storage. A key priority of the programme was to grow participation in demand-side response, making it easier for industrial and commercial businesses to get involved and to realise the financial and carbon-cutting benefits.

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[93] ESO, 2024. Virtual Energy System.
[94] ESO, 2024. Balancing programme.
[95] Inter-temporal dispatch optimisation across several settlement periods is currently a process and market challenge.

Power Responsive is still running as a regular stakeholder event, and has engendered a number of ESO programmes, including Bridging the Gap to Net Zero programme, ESO Markets Roadmap, Flexibility Market Strategy and Balancing Programme and other ESO-led initiatives.

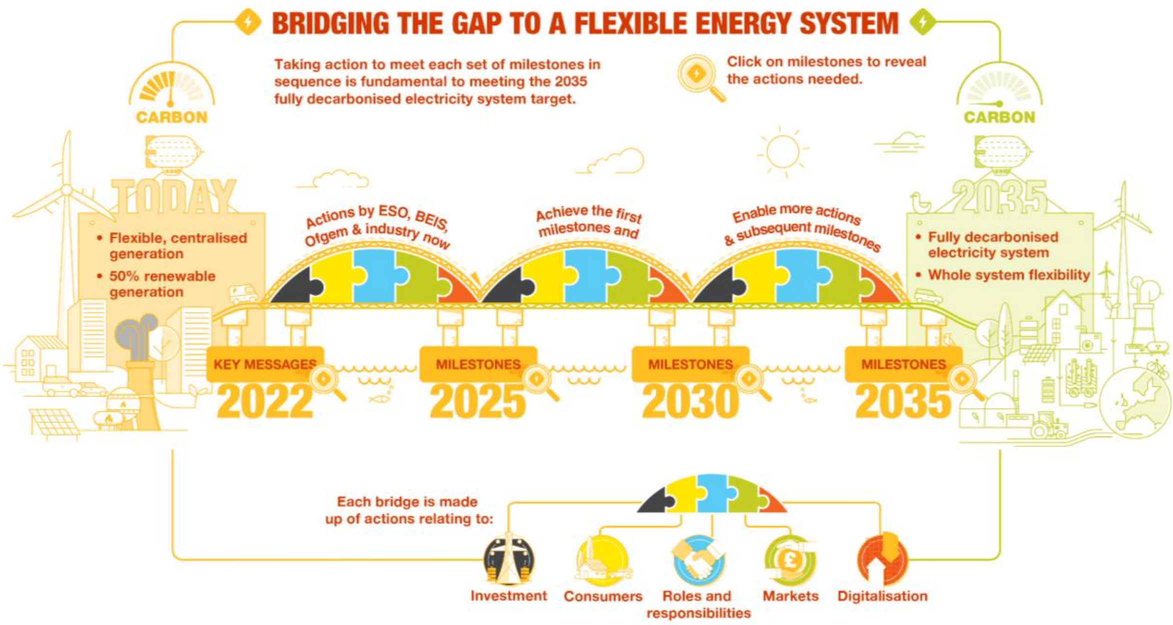

Figure 21. Bridging the gap has sought to engage stakeholders in the transition to smarter flexibility especially through data digitalisation.

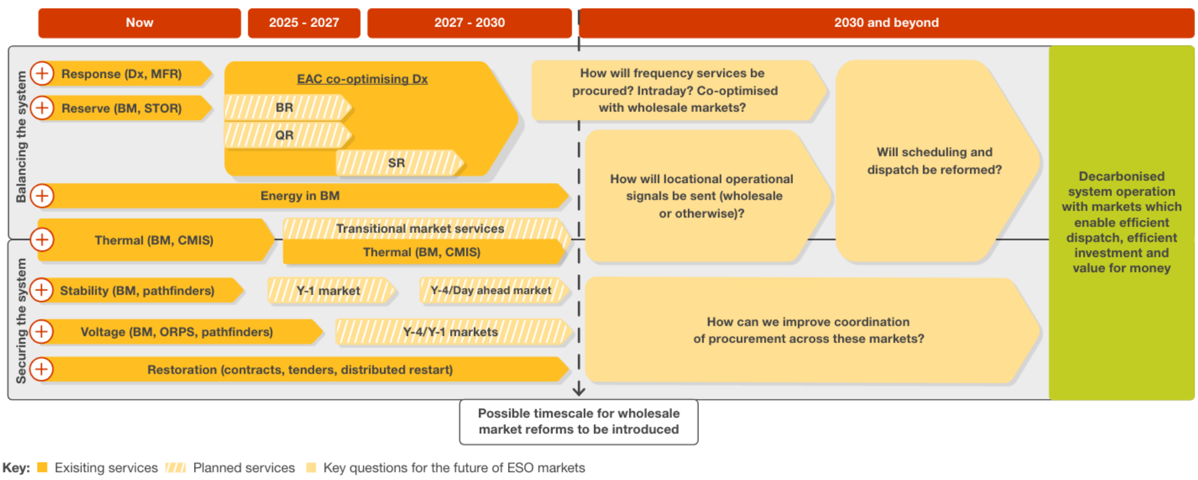

Figure 22. The new Markets Roadmap has sought to develop competitive markets for flexibility and ancillary services that would also stimulate investment.

The ESO has launched a call for input to a new Flexibility Market Strategy to:

> "support the evolution of demand side flexibility, from occasional events to day-to-day actions, by focusing on unlocking further access to core markets and a route to market for flexibility service providers, helping to incubate and encourage the emerging supply chain for demand side flexibility, and supporting the evolution of wider market signals to encourage and reward demand side flexibility." – **ESO June 2024**[96]

A progressive market reform agenda would build on the market development initiatives and programmes that have been developed. The success of the new market development relies on stimulating investment and market participation to access new revenue streams and long-term service contracts. This investment by market participants is likely to stall if we go through a process of radical, far-reaching market reform such as introducing zonal pricing, leading to an investment and innovation hiatus.

[96] ESO, 2024. Flexibility Market Strategy Call for Input – PowerPoint presentation.

C.4 Cross-border market strategy and efficient use of interconnectors

The third big opportunity for both strategic and operational reform is the efficient use of interconnectors. Although challenging politically, a focus on interconnection and cross-border energy trading could provide a means for the new UK government to develop closer alignment and collaboration with the EU, in an area which brings clear benefits both for UK and EU partners.

Interconnectors will play an increasingly important role in the future net zero energy system, allowing GB to export excess renewable energy when it is in abundance and to import energy from neighbouring markets when there is a shortage. In a high renewable energy system, interconnectors play a vital role in improving energy resilience, moderating consumer prices and allowing domestic generators to access export markets to increase their revenue potential – reducing the need for subsidy payments.

> "Interconnectors – high voltage cables linking Great Britain's energy system with our partners in Europe – are set to become a critical part of the UK's future energy system, providing much needed flexibility that will help to enhance energy security, reduce consumer electricity prices and enable the further growth of low carbon generation… we need to be very careful that Brexit doesn't result, whether through design or accident, in the isolation of the GB energy market from the wider European market. More generally Regen believes that the any future low carbon energy system must be based on a greater degree of cross-border and inter-regional integration and connectivity, supported by smart flexibility, not a move towards standalone energy markets." – **Regen short paper In Praise of High Voltage Interconnectors, 2017**

> New interconnectors using Voltage Source Converter (VSC) technology have the potential to provide technical services, such as voltage regulation and frequency response that will be important to operating and balancing Great Britain's transmission system, helping keep the network safe and secure as more renewable generation is connected. – **ESO Interconnector Analysis Report, March 2024**

Technically, interconnectors are ideal assets to provide flexibility services, with the ability to rapidly increase or change energy flows to respond to any system imbalance, although a key requirement of any flexibility that they do provide to the GB system is delivered in the full understanding of stakeholders in the connected markets, particularly the system operator. Therefore, in theory, they should be an ideal tool to improve system operation and market efficiency.

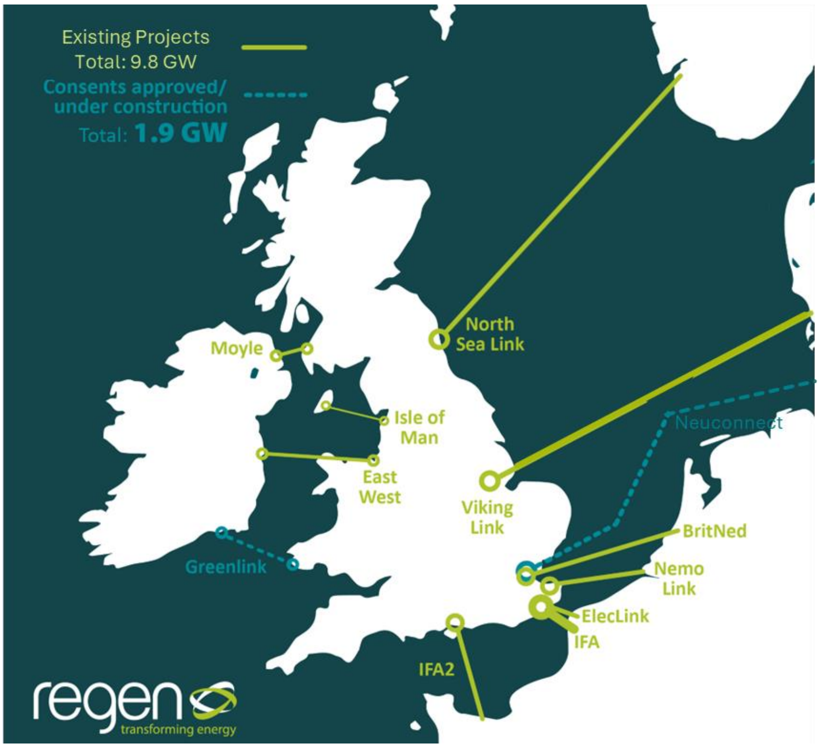

Figure 23. Current and pipeline GB interconnectors. There is at least another 10 GW of interconnector capacity in development.

In the past decade, the interconnector capacity between GB, Ireland, Norway and continental Europe has more than doubled to almost 10 GW and is expected to grow to over 25 GW by 2035.

The challenge and complexity with interconnectors, however, is that the both the investment and operational decision making, in both trading markets and as a balancing function, requires collaboration and coordination between at least two system operators and two market jurisdictions. In fact, in the context of the EU, interconnector coordination often reaches across multiple energy markets.

Two key operational problems have been identified in today's GB energy market:

1. **At times interconnector flows may run contrary to the prevailing GB wholesale price**. For example, GB may be exporting to France at a time when GB market prices are, at that moment, higher. This issue seems to be mainly the result of a misalignment between market trading windows and the timing of trades, and potentially differences in carbon prices. This has become a more significant issue since GB left the EU electricity market arrangements.
2. Interconnectors may flow into the GB energy system, correctly responding to a national price signal, but **into (or from) a part of the grid that is already constrained**, thereby compounding grid constraints and the need to manage them.

These two issues have been exacerbated by several factors that are not unique to the GB market, but may have worsened since Brexit:

- **There is a lack of an overall interconnector strategy** in GB (as evidenced by Ofgem's initial decision to reject cap and floor revenue support for six out of seven interconnectors that were in development), and it appears that GB is no longer fully engaged in wider EU interconnector planning and policy development.[97]

- **Since Brexit and the Trade and Cooperation Agreement (TCA), there has been a de-coupling of GB interconnectors from the wider EU energy market, including cross-border balancing platforms.**[98] Although this varies between interconnectors, as a practical consequence this means that trading across GB interconnectors is less efficient and can require separate transactions to trade capacity and volume.[99]
- The GB system operator does have some ability to affect interconnector flows (for example through forward counter-trading with market participants) and does make interventions to change flows. However, **these actions are considered to be both difficult to execute and expensive**. Interconnectors are, therefore, not fully exploited to provide system balancing services and are more often considered a system cost.

An underlying issue is the variety of cross-border trading arrangements that are in place and the limitations these place on the system operator.

The range of market tools interconnectors use varies from one interconnector to another. Some have day-ahead capacity auctions or are implicitly coupled with day-ahead energy auctions, while others do not participate in the day-ahead market at all. Similarly, some have intraday markets and others do not. Cross-border auctions occur at different time periods and under different trading arrangements.

Timing differences between cross-border and domestic markets may lead to incoherent pricing and are one reason that interconnectors may ‘flow in the wrong direction’, contrary to perceived price signals. Interconnectors connecting to the Great Britain National Electricity System (NETS) currently do not participate in the GB BM, so the ESO is unable to issue Bid Offer Acceptances (BOAs) on interconnectors post-gate closure, and is therefore reliant on capacity trading or emergency instructions to control interconnector flows.

> “This variance between interconnectors can lead to increased balancing costs due to different trading and flow control arrangements. Our ability to reliably trade capacity over interconnectors requires established, liquid and competitive commercial markets to enable it to trade at market reflective prices and to ensure trades are not easily unwound by other market participants. To date, the main market mechanisms to allow this are the day-ahead and intraday markets. Therefore, any interconnector that operates without a within day or day-ahead market structure means we are unable to alter the flow across the interconnector.”
> **– ESO Interconnector Analysis Report March 2024**

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[97] Ofgem, 2024. Initial Project Assessment of the third cap and floor window for electricity interconnectors.
[98] Euphemia, TERRE and MARI.
[99] The variety of interconnector arrangements and processes in place between Ireland, Norway and the rest of Europe has added to the problem and perception that the current market is unworkable.

Some improvements have now been made. For example, at present the 1.4 GW North Sea Link interconnector between Norway and the UK (at Blythe) only allows day-ahead implicit auction trading linked to the Nordpool power exchange. The Norwegian TSO Statnett has, however, announced plans to launch one or two daily intraday auctions, which should address some of the trading anomalies and inefficiencies seen on the North Sea Link and allow trading closer to time of delivery.[100]

C.4.1 Interconnector reform options

A lot of work is now being undertaken by the industry to look at the real problems that lie behind interconnector inefficiencies and to come up with practical solutions. A recent report by Frontier Economics for Scottish Power has highlighted some of these solutions.[101]

In brief, the options for progressive market reform fall into three main areas:

1. **Improving GB strategic planning and cross-border cooperation for interconnectors:**
    - Develop a UK interconnector strategy strategic plan within the SSEP which identifies specific locations and target connection dates for new interconnectors.
    - Include interconnectors within the CSNP for transmission network investment.
    - Shift from a reliance on developers to choose projects and develop interconnector projects to a strategic development approach. This could, for example, led to the development of an interconnector portfolio within the strategic spatial plan that could then be 'leased' in a manner akin to offshore wind farms or auctioned on a Design, Build, Finance, Operate (DBFO) type model.
    - Review the methodology and benefits case analysis used to approve GB interconnector revenue support, especially the use of scenarios, energy security valuation and assessment of consumer value.
    - Re-engage with EU institutions, neighbouring Transmission System Operators (TSOs) and regulators to co-develop future interconnection to ensure it delivers value to both GB and the connecting market.
    - Build on bilateral collaboration agreements e.g. GB Island of Ireland energy cooperation MOU.
2. **Improve interconnector market efficiency:**
    - Aim to recouple with EU trading markets – review, reform and then implement the proposed arrangements under Multi-Region Loose Volume Coupling (MRLVC).[102] The aspirational ambition should be to get back to full price coupling, although this could take time.
    - Align GB and IC trading timescales and markets and work towards a common approach for all interconnectors, which includes both day-ahead and intraday trading.

[100] As reported by Montel June 2024.
[101] Frontier Economics, 2024. Reform options for electricity balancing arrangements in Great Britain.
[102] The current proposals for the MRLVC have been criticised by a number of market participants and so need to be reviewed, with a clear programme for future reform and enhancement.

- Re-align GB-ETS /EU-ETS carbon pricing.
- Standardise interconnector trading arrangements and processes.

3. **Manage interconnector flows and enable interconnector balancing:**
    - Enhance and enable system operator-to-system operator counter-trading – energy and capacity – for example, looking at how TSOs in Germany and Denmark manage interconnector flows.
    - Enhance and enable system operator-forward market counter-trading.
    - Develop a new day-ahead Constraint Management Market (CMM) – enabling the ESO reserve/purchase capacity in the day-ahead market to manage constraints.[103]
    - Rejoin EU balancing arrangements to allow participation in interconnector balancing services.
    - Enabling interconnectors to contribute flexibility potential through CMMs.
    - Explore whether it is possible for interconnectors to participate in the BM or a parallel cross-border mechanism.

Overall, there is a need for a more holistic and strategic study of how interconnectors are developed and operated in the GB, leading to the establishment of an interconnector reform programme within the overall governance of REMA.

The complication of needing to work across borders, and in close collaboration with neighbouring system operators and market regulators, could be turned to an advantage if it part of a wider re-engagement and closer relationship with European energy markets. For example, GB should be more actively engaged in the development of the North Sea Regional energy strategy and cooperation agreements which are being developed between Scandinavian and north European markets. It is also likely that the energy chapters in the underlying Trade and Cooperation Agreement (TCA) will be reformed in 2026.

This should be a priority area for an incoming government and a potential area for a delivery taskforce to be established under the banner of the clean power mission.

[103] Enhancing the ESO's current ability to trade capacity – Interconnector Requirement and Auction Summary Data.

Theme D

Accelerating investment to create a renewables-based system at pace

The second REMA consultation objective is to accelerate investment in a renewables-based energy system. Protecting investor confidence is also one of the five key criteria which DESNZ defined in the consultation for use in assessing REMA reform options. Regen supports the direction of travel within the second REMA consultation to retain and expand the use of CfDs as the main revenue support mechanism for renewable energy projects, although there is still a role for other innovation and grant support schemes for new technology development. The CfD has so far provided contracts to support investment in 33 GW of renewable energy generation.

However, there is a need to have a more integrated approach to support investment across the entire energy system. It is not possible, or optimal, to focus on investment in renewable electricity generation without the accompanying investment in grid, storage, interconnectors, flexibility and dispatchable generation, or without consideration of the allied development of hydrogen, CCS, and transport-energy systems. There is also a need to consider the interdependencies between investment decisions and the opportunities for collaborative investment, which the current auction-based CfD arrangements may not facilitate.

The biggest challenge for market reform is to maintain and increase investment in renewable generation and flexibility at a time of changing market conditions. As GB increases its use of variable renewable energy and electrifies demand, longer and more intense periods of demand imbalance are anticipated, resulting in greater volatility in electricity prices, including negative price periods.

There are some examples of projects that have been financed based solely on merchant risk (short duration batteries and some solar PV being good examples) and some projects may be able to secure a long-term PPA to provide revenue confidence,[104] but investment in large-scale generation such as wind and nuclear, and long duration storage assets, will generally require some form of government-backed revenue security.

As an additional reform challenge, the greater the reform impact and the longer the transition phase from design to full implementation, the greater the need for government-backed revenue

[104] There are also now examples of hybrid projects that have opted for a part-PPA and part-CfD arrangement to hedge between a government-backed strike-price and market price risk.

security and 'grandfathering' of project investment. This is especially true if the nature of the reforms means that investors are unable to price in reform impacts.

Revenue security could be in the form of a Contract for Difference, regulated asset base investment model, long-term CM contract or a cap and floor-based scheme. There will also be a need to support legacy fossil fuel generation to act as a back-up or reserve capacity.

The progressive market reform agenda, therefore, includes the reform and enhancement of revenue support arrangements across the full energy system, so that they:

1. are effective in bringing forward investment at an accelerated pace
2. aligned with an overall net zero delivery plan
3. ensure value for the consumer in terms of energy supply, security and decarbonisation
4. minimise any adverse distortion in either investment or electricity markets
5. provide a means to improve, or not adversely impact, system operational efficiency.

Theme D: Summary reform agenda

Progressive market reform agenda	
D: Accelerating investment to create a renewables-based system at pace	
D1	Remove zonal pricing, make a quick decision on central or self-dispatch, and provide industry with a re-focused list of CfD reform options that would work with the preference wholesale market model. Bring all CfD reforms together under one reform programme.
D2	Review the CfD methodology and budget setting to accelerate CfD allocations. Consider the use of a threshold price alongside price competitive auctions to uplift allocations to meet clean power goals.
D3	Consider deeming CfD payments as a means to further de-risk investment and reduce market and operational distortions – but further analysis is required to understand impacts.
D4	Continue to develop and implement measures to include non-price factors within the CfD scheme, including the use of Sustainable Industry Rewards (SIR) and other incentives to deliver socio-economic benefits. Introduce a minimum SIR standard and an enhanced SIR award that could also be applied to non-CfD energy projects.
D5	Extend non-price factors to consider system benefits and how these can be rewarded within the CfD mechanism, including the value of generation diversity.
D6	Implement changes to the CfD scheme that would better facilitate collaborative investment in supporting infrastructure and supply chains.
D7	Align revenue support measures such as those for long duration storage, hydrogen power and CCUS with the overarching net zero strategic delivery plan and spatial plan.
D8	Conduct a review and reform of the PPA market with an objective to increase participation among corporate buyers, public procurement and local supply models.
D9	Enhance the use of PPAs, and encourage local energy supply, by reforming licence exemption regulations and guidance including the Electricity (Class Exemptions from the Requirement for a Licence) Order 2001.

D.1 Accelerating investment in CfD allocation rounds 7 to 9

It is understood that a new Labour government, with an urgent Clean Power mission, will make as few changes to the CfD scheme as possible in the short term and instead focus on setting an appropriate allocation budget, administrative strike price and budget reference price to boost the rate of renewable deployment.

For allocation round 6, which is already in progress, the options are likely to be limited to a potential resetting of the auction budget. For allocation rounds 7-9, the government could also consider switching from a single auction-based allocation round with a clearing price, to a threshold price auction at which it is willing to buy a set GW of capacity. Or combining an ongoing auction process with the option to accept a set early-offer 'buy-now' price.

A further, relatively simple, option would be to extend the CfD period/term to 20 years or the estimated life of the asset.

D.2 Improving the CfD mechanism

There are a lot of reforms and changes currently in the policy pipeline related to CfDs. These include ongoing reforms which are being developed as part of the 'post-allocation round 7' consultation and broader reform options that have been proposed under the REMA programme.

As a general observation, and based on feedback from Regen's industry engagement, it has become very difficult for industry stakeholders to track and follow these different reform initiatives or to differentiate between long-term and near-term CfD reforms. This lack of clarity as to the scope and timing of reform is potentially increasing investor uncertainty. We have therefore recommended that all CfD reforms be brought together under one programme and engagement process.

A further complication is that it is not clear which CfD reforms would be compatible with other potential market designs. This is especially true if the government were to adopt zonal pricing, which would require a significant re-working of the CfD design. Regen's recommendation is to remove zonal pricing as an option, make a quick decision on central or self-dispatch, and provide industry with a re-focused list of CfD reform options that would work with the preferred wholesale market model.

Looking further ahead, across both the REMA and ongoing CfD reform initiatives, the agenda for progressive market reform includes a number of CfD-related challenges:

1. How can CfDs continue to **reduce investment risk and accelerate the deployment** of low-carbon generation against a backdrop of increased market price and volume risk? Or, to flip this question, what is the appropriate level of market risk that will achieve the UK's investment targets while securing the optimal cost of energy for consumers?

2. How do CFDs value **'non-price factors'** including economic development, UK and regional supply chains, environmental value and wider system benefits?
3. How do CfDs affect **market behaviour and create potential distortions** in the market such as negative price periods and the loss of liquidity in forward markets? Market behaviour can then lead to **operational inefficiencies**.
4. Could CfDs **inhibit generators from participating in ancillary service markets**, or 'behind the meter' type applications in storage and hydrogen production?
5. If nearly all new generation is CfD-backed, does this create a **more fundamental market distortion** e.g. putting non-CfD projects at a competitive disadvantage or preventing other forms of forward market hedging?

Proposed solutions in the REMA consultation and technical research papers to balance investment risk versus market distortion and system operational costs include shifting CfD payments from actual metered generation to a **form of deemed (potential) generation**.[105] This change would decrease the volume risk faced by CfD generators, and (all else being equal) lead to lower strike prices at CfD allocation auctions. Deeming would expose generators to wholesale day-ahead price signals, incentivising generators to reduce generation during negative price periods and/or seek alternative markets and value sources for their electricity when revenues from these alternative markets would exceed those from the wholesale market.

Deeming CfD payments warrants deeper analysis as it could meet both objectives of supporting investor confidence and reducing system costs. However, it represents a significant change to the basis of the CfD scheme and requires thorough evaluation against value-for-money criteria and a clear test of whether it would lead to lower CfD strike prices. Deeming could also have unintended market impacts and implications for non-CfD and legacy CfD holders, which need to be considered.

A key question for the design of a deemed CfD is what would happen during negative price periods, and whether a better outcome could be obtained by encouraging other forms of flexibility to take advantage of negative prices, rather than resorting to generation curtailment.

The REMA consultation also proposes a strategy to restrict CfDs to a proportion of a project's installed capacity, leaving some capacity to operate on a merchant basis and, therefore, partially exposed to market signals. While the voluntary adoption of partial CfDs is viewed positively, enhancing liquidity in forward markets and offering an additional hedge against investment risk, mandating partial CfDs could be problematic. This is particularly relevant for smaller renewables projects, as securing long-term contracts for the merchant portion can be challenging. Additionally, mandatory partial CfDs might necessitate high credit ratings for project finance, potentially limiting the pool of viable counterparties and/or putting up the cost of capital.

[105] Cornwall Insight and Frontier, 2023. Market signals and renewable investment behaviour.

From a progressive market reform perspective, optimising investment risk, while reducing both costs to the consumer and operational costs, is a sensible objective. Of the options considered, deeming CfD payments would appear to have merit. However, all of the options require significantly more analysis to understand their direct and indirect impacts.

D.3 Considering non-price factors

D.3.1 Building sustainable supply chains

The progressive reform agenda would include the consideration of non-price factors which could be addressed both within the CfD market design and the way the CfD scheme is administered within the overall project development, leasing and planning regime.

The proposal to introduce Sustainable Industry Rewards (SIRs) from Allocation Round 7 has been welcomed by the industry. SIRs will provide an additional award (alongside regular CfDs) to offshore wind farms that commit to provide enhanced economic value for the UK alongside more sustainable supply chains.

Following a consultation in November 2023, the government has indicated that it will introduce SIR contracts from Allocation Round 7, but on the basis of a 'lighter touch' approach, that would include fewer criteria than when the concept was first proposed:

1. Investment in shortening supply chains, in deprived areas in the UK; or
2. Investment in more sustainable means of production, anywhere in the world; or
3. Combining both approaches, by investing in shorter supply chains in UK deprived areas and ensuring such investment goes to more sustainable means of production.

Regen has welcomed these proposals, but recommended splitting the SIR scheme into a minimum and enhanced SIR standard and to widen the award of SIRs beyond CfD projects. This would allow a minimum SIR standard to be applied as a qualification stage to a CfD, or other revenue support arrangement, and then for enhanced SIRs to be awarded based on delivery performance.

- **Minimum SIR standards** which could be introduced as entry criteria for the CfD scheme.
- **Enhanced SIR scheme** (beyond the minimum) which could be introduced as a separate reward/penalty contract and could be offered to non-CfD projects, partial CfD projects and existing CfD contract holders.

D.3.2 Recognising the value of system benefits

There are different pots for different technologies, and minima that can be set, but as a general rule the CfD scheme places value on the quantity of electrons generated and not whether those electrons have been generated at the right time and place. Combined with competitive auctions, the CfD scheme can encourage a clustering of assets using the lowest cost of energy technologies and locations. For example, the clustering of windfarms in the southern North Sea area.

The lack of recognition for system value within the CfD scheme has been highlighted by Regen's Go West! analysis, which looked at the energy system benefits of a more diversified offshore wind portfolio with a more balanced East-West split of windfarms. Given the UK's prevailing weather systems, the more balanced portfolio delivered significant system benefits with fewer and shorter extreme high or low wind periods and less volatility in wind output between periods.

As it currently stands, however, the CfD scheme would not provide additional support to a windfarm whose location helped to offset high and low generation in the market.

D.4 Supporting collaborative and strategic investment

One of the biggest challenges for the CfD scheme, which has not been addressed by REMA, is how the scheme will support collaborative investment by generation projects, infrastructure providers and regional stakeholders.

As the UK builds out more offshore wind and other renewable technologies, developers are increasingly being asked to find ways to save cost and reduce environmental and societal impacts through collaboration. This, in turn, creates an interdependency between projects which the CfD scheme is not designed to support.

The UK is shifting from a pipeline of individual and independent generation projects to a more strategic net zero delivery plan, where projects become more dependent on co-investment in shared infrastructure, grid, ports, supply chains, skills, biodiversity gains and other enablers. This has, in part, been driven by the shift to strategic network planning and investment – as seen, for example, through the holistic network design process.

Celtic Sea offshore wind is a very good example of this, with plans to develop three projects of up to 4.5 GW with a future expansion of a further 12 GW. The Celtic Sea projects are a fantastic opportunity for the UK industry and for the regional economy. However, this strategic development approach will only work if all three projects are delivered in the right time period and sequence, so co-investment can be made in ports, supply chains and grid infrastructure.

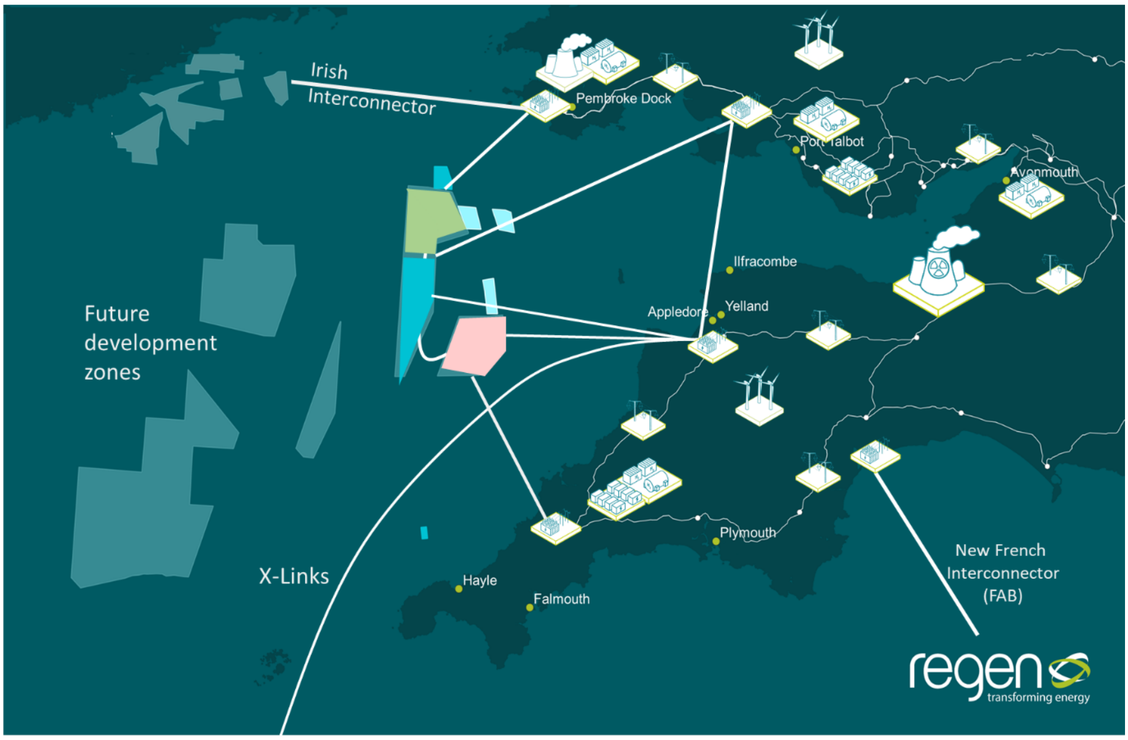

Figure 24. Celtic Sea – an area rich with opportunities but requiring a strategic approach.

The CfD scheme is currently a barrier to this type of strategic co-investment because a) projects are expected to bid against each other in a competitive auction, whereby one or more project may fail to get an award, and b) because the CfD allocations come late in the project lifecycle – too late for most types of collaborative investment.

Addressing this issue would require a rethink in terms of how and when the CfD allocations are made. This might involve:

1. Awarding CfDs earlier in the process, potentially at the time of lease award, as is common in other EU countries. It would make sense to award lease, grid connection and CfD together as a single package.
2. Enabling projects that are reliant on co-dependent investments to secure a CfD collectively, via a joint bid or facilitated by running regional CfD allocations.
3. Shifting towards negotiated and coordinated CfD allocations, or transitioning towards a 'hurdle' system as suggested by Offshore Wind Champion Tim Pick,[106] whereby projects can be awarded a CfD earlier in the development timeline on the condition that they satisfy a number of requirements and their strike price is within a certain threshold.

[106] Offshore Wind Champion Independent Report 2023.

"HMG should continue (in the context of REMA, or separately) to explore possibilities for bringing forward the award of CfDs (or future subsidy / route-to-market mechanism), potentially on an as-of-right rather than auction basis, thereby facilitating a more accelerated approach to project development and allowing greater collaboration and earlier placing of orders with the supply chain giving time to make investments." – **Offshore Wind Champion Independent Report 2023**

Theme E

From fossil fuels to low-carbon flexibility and dispatchable generation

Regen has submitted responses to the three Capacity Market (CM) consultations published by Ofgem and DESNZ in the last 18 months.[107;108;109] The phase one consultation, published in early 2023, reflected more widely on the purpose and design of the CM with a focus on four critical outcomes:

1. **Capacity adequacy** – ensuring that the CM and/or other mechanisms are sufficient for an adequate capacity margin over both the short and long term.
2. **Decarbonisation** – ensuring that the CM supports (and does not hinder) the UK's net zero targets.
3. **Flexibility and resilience** – ensuring that the market provides not just capacity, but other attributes and capabilities that will be essential in providing resilience and security in a more dynamic future energy system.
4. **Value for money** – ensuring that a) the CM works efficiently to secure energy security at a competitive price and b) that assets that are being supported via the CM are prevented from gaming and exploiting their position in the BM.

The REMA consultation addresses a number of these points with a focus on changes to the CM that would encourage investment in low-carbon flexibility and, over time, would incentivise unabated fossil fuel plants to either decarbonise or decommission (subject to energy security requirements).

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[107] DESNZ, 2023. Capacity Market 2023: strengthening security of supply and alignment with net zero (Phase 1).
[108] DESNZ, 2023. Capacity Market 2023: Phase 2 proposals and 10 year review.
[109] Ofgem, 2024. Ten-year review of the Capacity Market Rules – consultation.

Theme E: Summary reform agenda

Progressive market reform agenda	
E: From unabated gas to low-carbon flexibility and dispatchable generation	
E1	Promote a more rapid use of incentives and obligations to encourage the transition from unabated gas to low-carbon fuels and technology. Providing additional support for low-carbon flexibility through the CM.
E2	Include complementary technology development and revenue support for key technologies including long duration storage, CCUS and hydrogen generation. Accelerate development of hydrogen generation using green hydrogen and implement revenue support for long duration storage.
E3	Include a Strategic Reserve to provide a means to remove ‘end of life’ fossil fuel plants from both the capacity and wholesale markets while still retaining their use for back-up and energy security.
E4	Provide more detail on how a single auction with multiple clearing prices and minima would work.
E5	Conduct a review of current and future CM purpose, costs, competition and value for money.

E.1 Providing additional support for low-carbon flexibility through the Capacity Market

The REMA focus to support a transition from unabated gas to low-carbon forms of flexibility has been on reforms to the CM. In this area REMA has considered a number of options to provide greater incentives for low-carbon flexibility in the CM, including:

1. **A split auction** with separate auction cycles and procurement targets for different technology types – which would run sequentially so that low-carbon flex is procured first.
2. **A single auction** with multiple clearing prices, using minima to set procurement targets for different technology types.
3. **A single auction with multipliers,** which would provide technologies with an uplifted clearing price based on their desirable characteristics – low carbon, response time, duration etc.

The second REMA consultation report has suggested that option 2, a **single auction with multiple clearing prices and minima**, would be the preferred option, as it would be the easiest to implement and send the clearest investment signal.

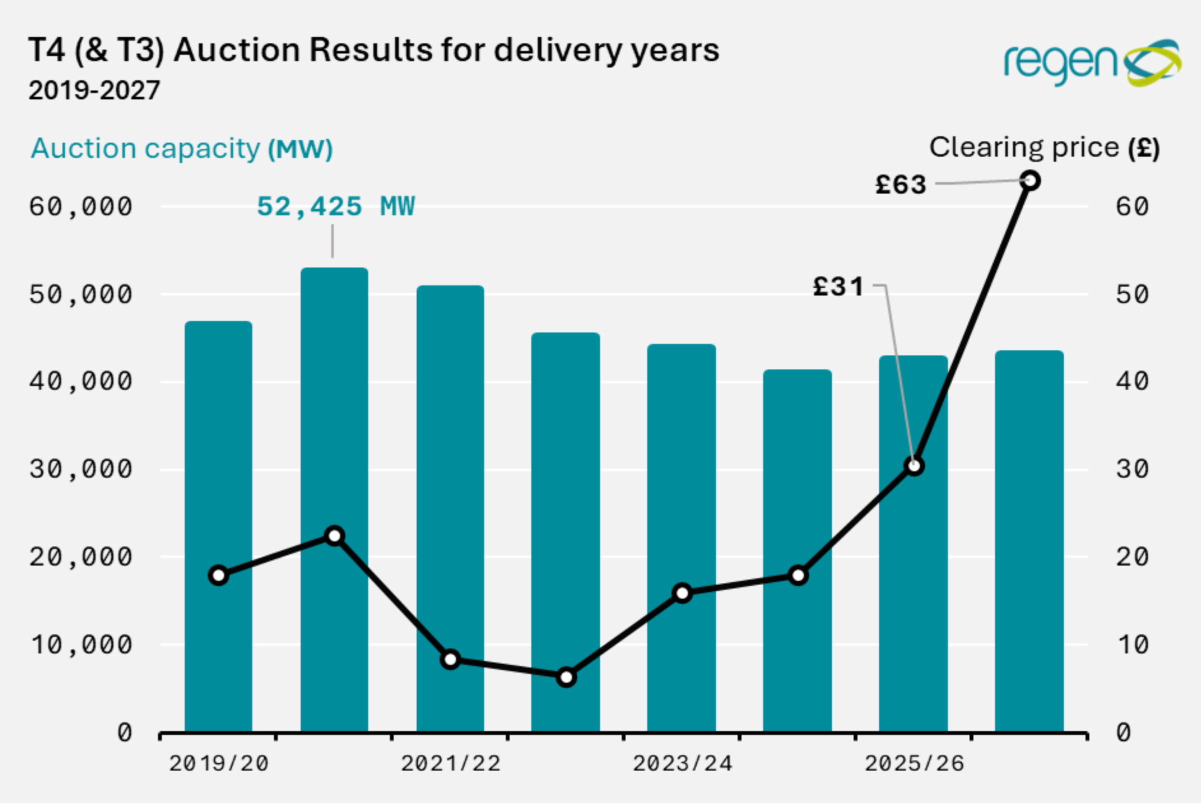

Figure 25. Capacity market auction results between 2019 and 2027.

Further detail on how the single auction with minima would work is needed. More analysis is also needed on the future cost of the CM, the value for money and the degree of price competition.

We also note that CM costs have risen significantly over the past five years and have now reached £65 per kW. We question whether this level of cost increase is sustainable.

Other CM reforms

We are aware that there are several other CM reforms in development which, similar to the CfD reforms, are causing some confusion and lack of clarity for industry stakeholders. We would recommend consolidating all CM reforms together into a single programme of work and engagement under the broader REMA governance framework.

Regen's priorities for CM reform include:

- A review of the storage de-rating factor methodology by the Electricity System Operator (ESO) needs to be done with a wider review of the appropriateness and methodology of de-rating factors and within the context of wider CM reform.
- DESNZ should review the requirements for an extended performance test, including whether an equivalent mechanism should be introduced for all technologies participating in the CM. If continued, DESNZ should reduce the frequency of extended performance tests in the CM for storage Capacity Market Units (CMUs).

- The government should develop a mechanism to be applied across all technologies to allow CMUs to provide an expected capacity curve for the 15-year contract period – this could be reassessed (annually) to update with levels of degradation.
- Provide an optimised process for co-located battery storage sites to participate in CM, via a new generating technology class and consultation process.

E.2 Incentivising fossil fuel plants to convert to low-carbon technology and fuels

Requiring fossil fuel generation plants to convert to low-carbon fuels and technologies will be critical to achieve the GB energy strategy. This could be done through the CM by setting tougher emissions limits, and by limiting the availability and duration of CM contracts to unabated generators. No new CM contracts should be offered with a long-term (beyond 2035) contract without a plan for the plant to convert to a low-carbon technology.

The REMA consultation, and other government policy documents, have identified seven options to encourage unabated plant conversion:

1. **Setting emission limits to receive a CM contract.** The January 2023 CM consultation proposed that new and refurbishing CMUs with multi-year agreements beyond 2034 (from 1 October 2034) must meet an emissions intensity limit of 100gCO2/kWh or a yearly emissions limit of 350kgCO2/kW. The emissions limit would limit operations to approximately 750 hours per year for a typical gas peaking plant. This proposal is still under consideration, but the government has stated that it would not be introduced until CM 2026 auctions at the earliest. Regen would call for a more rapid implementation.
2. **CM 'managed exits'** Allowing existing fossil fuel CM contract holders to exit their CM contracts to allow them time to refurbish their plant and access a new CM agreement or alternative support schemes to decarbonise, subject to ensuring continued security of supply and certain conditions being met.
3. **Providing financial support for low-carbon conversion,** such as the bespoke support schemes like the Dispatchable Power Agreement (DPA) for CCUS.
4. **Enabling hydrogen generation and power CCUS to participate in the CM,** establishing a generating technology class in the CM for power CCUS.
5. **Extending the CM term for refurbished plants** from three years to nine years.
6. **Requiring decarbonisation readiness** to ensure that new build and substantially refurbishing combustion electricity generators are built in such a way that they can easily decarbonise in the future, either by converting to 100% hydrogen-firing or retrofitting carbon capture within the plant's lifetime. Although there is a risk here that readiness does not lead to conversion unless CM term and emission limits are imposed.

7. **Carbon pricing:** As a backstop, carbon pricing is a useful driver of decarbonisation. The GB Emissions Trading Scheme (ETS) has fallen significantly below the equivalent EU ETS, and may not be compatible with the UK's net zero targets. The government has proposed to reduce the UK ETS cap to bring carbon prices in line with net zero targets and to smooth the transition to higher carbon prices.[110]

All seven measures could play a role to support the decarbonisation of the power sector and should be included in the progressive market reform agenda. The key consideration is how quickly they can be implemented. There has been a policy trend to propose steps that could be quite radical, for example setting tougher emission limits or higher carbon prices, but then to delay their introduction or mitigate their impact. More clarity is needed from DESNZ on which of these options are being progressed and the timeframe.

E.3 Developing new and existing markets for flexibility services

The CM is important to provide investment support, but is one of several potential revenue streams that can be harnessed by providers of flexibility services.

The creation of the Enhanced Frequency Response service by the ESO in 2017 is a great example of how the coordinated development of a new market service, in this case for frequency response, helped to jump-start investment in battery storage and provide a cost-efficient service to the system operator.

The frequency response market has since evolved and developed into a range of dynamic control services, which have helped GB increase levels of low-carbon generation. As the frequency response market has become more competitive prices have fallen, and so flex providers are now looking to expand into new markets, including wholesale price arbitrage, BM and local constraint management at both the distribution and transmission level.

Developing the markets for flexibility services was a key part of the Ofgem/DESNZ Smart and Flexible Energy Plan 2021 and is critical for the long-term development of storage, demand side flexibility and interconnectors.

Since then there have been a number of positive developments in the flexibility and ancillary markets area, including the expansion of distribution network flexibility contracts which, in 2023, reached just under 5 GW contracts tendered and 2 GW[111] contracted and have become a business-as-usual function to manage constraints on the distribution networks.

Progress for transmission-level constraint management and for overall system balancing has been slower and has been hampered by a number of limitations and barriers within the control

[110] DESNZ, 2023. Developing the UK Emissions Trading Scheme: Main Response.
[111] ENA analysis of flex markets in 2023.

room function, including the challenge of dispatching multiple smaller assets and limits such as the '15-minute rule'.[112] These operational issues, which are discussed further in Theme C of this report, resulted in very high 'skip rates'[113] for batteries and other flexibility providers in the BM.[114] The ESO has responded[115] to these issues with a programme of reforms including a further widening of BM access and a new Open Balancing Platform, implemented in December 2023, to increase the control room's ability to dispatch multiple assets and an uplift of the 15-minute rule to 30 minutes.

Already these relatively simple changes have begun to have impact, with a reported 47% increase in battery unit dispatch rates[116] but there is still a lot more that can be done to improve BM efficiency and to provide the control room with new the process and system capabilities to manage a net zero power system.

Opening up the BM to low-carbon flexibility providers and the creation of new ancillary markets for flexibility services can provide an effective stimulus for investment and the transition away from larger, less flexible, fossil fuel plants.

E.4 Supporting investment in long duration storage and low-carbon dispatchable generation

Although outside the REMA core scope, it's clear that long duration storage and dispatchable generation assets will require additional investment and revenue support in order to reach the scale and maturity level at which costs can be reduced and they can be competitive. This includes:

- Long duration storage – for which the government has proposed a cap and floor type model.
- Generation with CCUS – for which DESNZ has published an updated CCUS Vision document backed by a number of grant and innovation funding schemes targeting CCUS clusters.
- Generation from hydrogen – for which the government has published a hydrogen strategy and run a number of funding competitions for hydrogen production plants.

[112] A operating rule that batteries can only be dispatched in the BM for 15 minutes – caused by a lack of available data on battery state of charge.
[113] A 'skip' being an instance where a lower-cost asset is skipped in favour of a higher-cost asset within the BM, either because of an operational reason or because of limitations in the ability of the control room to dispatch certain types of asset.
[114] Analysis by Modo, Arenko and others have shown very high skip rates and consequently very low utilisation of battery assets in the BM, despite these assets offering lower Bid and Offer prices.
[115] See ESO Response to Electricity Storage Network Letter.
[116] MODO analysis reported in Current, 15 March 2024.

CCUS and hydrogen power generation technologies could also benefit from a Dispatchable Power Agreement (DPA) model that provides an availability payment, which is paid regardless of whether a facility is dispatching, and so will not incentivise facilities to displace lower-cost and lower-carbon sources of generation such as renewables and nuclear.

These strategies and funding support schemes are positive, but it remains the case that CCUS is significantly behind where it should be, with very few working CCUS plants at scale, and only a few plants planning to convert to CCUS in the near term.

Hydrogen generation – using 100% or a blend of hydrogen – is still at an early stage of development although there are a number of hydrogen turbines available and the possibility to convert existing generation plants quite quickly to a hydrogen blend. A big challenge, however, is that the full hydrogen value chain[117] has not been developed, including the required levels of production, storage and distribution.

Regen and the ESO identified the importance of dispatchable generation to the operation of a net zero energy system in the Day in the Life 2035 study of a future electricity system. The study identified CCUS delivery as a key uncertainty and area of risk.

Given that low-carbon dispatchable generation will be critical to deliver a net zero power system by 2035, it is essential that the deployment of both CCUS and hydrogen generation is accelerated. Developing the technical and commercial readiness of these technologies, and supporting them to catch up with variable renewable generation, will be critical to the success of a progressive reform agenda.

On a positive note, while the development of CCUS remains uncertain, the cost of battery storage has dropped significantly and there is a very strong pipeline of storage projects in the connection queue at both transmission and distribution. A remodelling the future electricity system in 2035 would probably now include a higher level of both short and long duration energy storage.

E.5 Managing legacy fossil fuel plants while maintaining energy security

Policymakers need to consider how to manage end-of-life fossil assets that should not participate in the market, but may need to be retained as standby and backup generation.

The second REMA consultation proposed to remove the Strategic Reserve option, and to push instead to ensure that fossil plant is either converted to low-carbon or shut down. In practice however, there will probably need to be a process in place to ensure that the decommissioning of legacy plants does not put energy security at risk.

[117] Regen, 2021. Building the Hydrogen Value Chain.

It is noted that the Labour 2024 election manifesto included a pledge that "*Labour will maintain a strategic reserve of gas power stations to guarantee security of supply*".[118]

As we explored in our CM insight paper, [119] as emissions limits tighten and as carbon signals are strengthened in the wholesale markets, some of these older plants with no financially viable route to decarbonisation will find themselves facing closure. Leaving these plants within the CM is one option but would push up CM costs and may not provide good value for consumer.

The current arrangement for coal fired power stations has been criticised, due to a lack of transparency and consistency in the way that coal plants have been dispatched. This may, in part, be due to the way the coal contracts have been established and the lack of an overall market design for legacy plants.

Regen's view is that it would be better to deal with this issue in a direct and transparent way. Whether this is through a reformed Strategic Reserve, that addresses the market concerns regarding dispatch transparency, or another approach needs to be considered, including, in extremis, a form of state ownership.

A well-designed solution could enable the ESO to actively manage these assets, and their removal from energy markets, in a way that maintains energy security at an affordable cost, while ensuring that their presence does not slow or stymy the transition to a net zero energy system or impact liquidity in the CM.

The risk of dropping any solution for legacy fossil fuel plant from the REMA scope is that a future government will be forced into a poorly designed solution that will not provide a fair cost to the consumer, with the risk that contracting unabated gas plants at a high cost to remain on standby might incentivise these to be used inappropriately. This underscores the importance of a well-designed mechanism that is clear and transparent.

[118] Labour, 2024. Labour's Manifesto/Make Britain a clean energy superpower.
[119] Regen, 2023. Capacity Market Reform.

Theme F

Passing the value of low-cost renewables to consumers

The first REMA challenge is to ensure that the value of lower-cost renewables is passed to the consumer rather than being captured as excess profits (inframarginal rents) or system costs by generators, traders and energy supply companies.

The focus on inframarginal rent[120] capture became a hot topic during the energy crisis and is the main reason that the split market option was considered – it also led to the introduction of the Electricity Generator Levy windfall tax. Inframarginal rent capture is also part[121] of the producer to consumer value transfer which is modelled as a 'consumer benefit' within the LMP benefit case.

Unfortunately, while the split market and LMP solutions would, in theory,[122] drive some infra-marginal rent value from the producer to consumer, they would do so as a zero-sum transfer that would also increase investment risk, the cost of capital, revenue support measures and, ultimately, the cost to the consumer. More broadly, an attempt to completely remove inframarginal rent is misplaced in a high renewable energy system because the marginal cost of variable renewables (and nuclear) is near zero, and is less than the average or levelised cost of energy required to provide investors with a reasonable return on investment. To put this another way, inframarginal rent (or another form of revenue support) is required to enable developers to repay their capital investment. This becomes a more significant issue for technologies with high capital costs – renewables, long duration storage, CCS and nuclear.

The progressive market reform agenda would focus on ways to ensure an equitable and sustainable value share between consumers and producers that allows consumers to benefit from lower-cost renewables, but also provides a fair investment return for the producer. The goal to simultaneously provide the consumer with lower-cost energy while reducing investment risk is a better basis for market reform than an unsustainable value transfer.

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[120] Inframarginal rent – the revenue above marginal cost enjoyed by a lower-cost producer selling into a market where the price is set by a higher-cost producer – e.g. wind, solar or nuclear selling at a market clearing price set by higher-cost gas generators.

[121] The producer to consumer value transfer under LMP is mainly the result of squeezing out inframarginal rents by assuming marginal pricing at the location and also the loss of constraint payments. The loss of price competition at some locations leading to higher rent taking by some generators is usually not modelled.

[122] In practice, value transfers from producers would have to be mitigated by grandfathering existing revenue and access rights and by offering further revenue guarantees via CfDs, RAB and Cap and Floor models. There are also liquidity risks that could lead to higher rent taking in some locations.

While the value share between producers and consumers is very important and is rightly considered as the key market reform challenge, other aspects of consumer value also need to be considered as part of the progressive market reform agenda. These additional aspects include:

- Targeted value transfer to alleviate fuel poverty and support the levelling up agenda.
- Ensuring fairness and justice between different localities, different consumer groups and between different fuel types.
- Supporting local energy supply and ownership models to ensure that consumers and communities benefit from energy infrastructure investment in their locality.
- Enabling consumers to participate in the energy markets by providing flexibility, while not unfairly penalising those consumers with less flexibility to offer because of their energy usage, access to low-carbon/smart technology or local network constraints.

Theme F: Summary reform agenda

Progressive Reform Agenda	
F: Markets that work for the consumer – passing the value of lower-cost renewables to consumers	
F1	Develop market arrangements that will maintain a balanced portfolio of electricity supply under CfD contracts, long-term PPAs and short-term marginal price markets in order to maintain a balance between forward hedging, liquidity and price competition.
F2	Leverage revenue support arrangements which have an inbuilt value share by expanding the use of CfDs for new renewable generation and repowering existing sites.
F3	Ensure that there is transparency and accountability to demonstrate that the benefits of negative CfD payments during high wholesale price periods are fully transferred to the consumer and not retained as energy supply company profits.
F4	Implement regulatory and market reforms to remove barriers to encourage the use of long-term PPAs and a means to ensure that consumers benefit from long-term contracts that provide generators with additional revenue certainty.

F.1 Enabling a fair deal between consumers and producers

The goal to simultaneously provide the consumer with lower-cost energy while reducing investment risk can be achieved in a number of ways:

1. Leveraging revenue support arrangements which have an inbuilt value share.
2. Increasing the use of long-term contracts via PPAs and possibly green power pools.
3. Maintaining competition (liquidity) in short-term 'marginal price' markets.

The optimal market design that makes best use of GB bilateral trading arrangements would almost certainly involve a portfolio approach, with a mix of long-term and short-term price markets order to maintain a balance between forward hedging, liquidity and price competition.

In extremis, a form of windfall tax could be imposed. Windfall taxes are not ideal and have obvious drawbacks for investor confidence but, in principle, a well-targeted and time-limited windfall tax (unlike the current Electricity Generator Levy[123] which runs to 2028) could provide a fallback option if other market reforms proved to be ineffective. Windfall taxes are not part of the progressive reform agenda, but should nevertheless be considered as a fallback option in preference to a complete market redesign.

F.2 Leveraging revenue support mechanisms to provide a hedge against future price rises

Extending the use of Contracts for Difference, regulated asset base and cap and floor models – all of which have a mechanism for consumer value share.

The reform of the CfD scheme from the perspective of generation investment and operational efficiency has already been covered under Theme C. In this section we discuss how the CfD scheme can provide a means to transfer value to the consumer by providing an energy price hedge against future high energy prices and a value share based on the generator's willingness to give up value to the consumer (via the levy framework) in exchange for greater long-term revenue certainty. C.4.1

The focus of the REMA consultation has been on the extension in the use of CfDs, which have an in-built value transfer to consumers via the negative CfD payment (payback) from the producer during periods when the wholesale reference prices is above their CfD strike price.

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[123] Regen has previously criticised the design of Electricity Generator Levy and the lack of accompanying investment support.

The potential of this value share mechanism, which is a form of future hedge against high prices for GB consumers, came to the fore during the 2021/22 energy price crisis, when many CfD holders were regularly making payments back to consumers via the CfD levy.

Extending the use of CfDs to provide consumer value could be achieved in a number of ways:

- **Maintaining liquidity, price discovery and competition within the CfD mechanism**. In order for CfDs to provide a fair price for the consumer, there needs to be a form of price discovery that achieves an equitable price for the generator and consumer. At the moment this is mainly achieved via competitive auctions. A balance needs to be struck, however, between price competition and the need to accelerate investment. Auctions may also be less appropriate in the case of strategic investment and co-investment between projects.
- **Accelerating the delivery of new renewable generation** capacity under the CfD arrangements. For example, it is likely that a future government will need to greatly uplift the allocation budgets for CfD allocation rounds 7-9[124] in order to get the deployment of offshore wind back on track to meet future decarbonisation of power targets.
- **Extending CfDs contracts to repowering projects** on the basis that they will be investing in new technology and new capacity. This proposal is currently the subject of a separate CfD consultation for allocation round 7 and beyond.
- **Offering hybrid CfD or part-capacity CfDs,** under which generators are able to enter into CfD contracts for a proportion of their generation capacity. This has the advantage of maintaining some capacity that is exposed to merchant price signals and thereby potentially encouraging greater liquidity in both intraday and forward markets.
- **A further option to offer a CfD-type contract to existing generators** in exchange for their remaining Renewable Obligation subsidies was previously suggested by government but has not been pursued. This probably would have been a good idea a few years ago, and even better at the time CfDs were introduced, but may have less merit now given that the Electricity Generator Levy (windfall tax) will run to 2028.

RAB and cap and floor models also have the means to deliver a value share arrangement, although their use for higher-cost nuclear, dispatchable generation and asset finance (e.g. long duration storage and interconnectors) probably means that these measures are more a means to share investment risk rather than deliver lower-cost energy.

[124] As a result of the challenges in allocation round 4, lack of offshore wind in allocation round 5 and expected capacity in allocation round 6, the GB is far off track to decarbonise power by 2035.

F.3 Extending the use of long-term PPA contracts for businesses, public and third sector organisations and supply companies

Regen welcomes the proposal that REMA should explore the role of Corporate Power Purchase Agreements (CPPAs) as a route to develop renewable generation. Falling under the wider umbrella of PPAs[125], CPPAs are defined in the consultation as 'long-term agreements for the purchase of electricity at an agreed price between a developer and a corporate counterparty'. This includes businesses and public sector organisations, with the purchasing of electricity often undertaken via an intermediary supply licence holder or 'sleever'.

The use of long-term PPAs was rather overlooked in the first REMA consultation, so it is positive that they have been included as a credible market option for exploration and have been included in this second consultation. However, barriers such as high counterparty risk, high transaction costs and contract length/demand mismatches restrict PPAs to large, stable off-takers, with good credit ratings and the ability to sign long-term contracts. This is particularly challenging for the development of smaller-scale renewables.

Like CfDs, PPAs are a form of long-term contract which typically benefits both generators and consumers. The availability of PPAs encourages participation in forward markets by providing a route to purchase energy over a long-term contract. They are key tools to provide the revenue certainty needed to enable developers without a CfD to raise finance for investment in generation assets.

It is difficult to generalise about PPAs given that many different structures and commercial conditions can be attached to them, but in general:

- PPAs provide a long-term price contract, although these can come in many forms, from fixed prices, inflation-linked and private CfD-type arrangements as well as contracts that are indexed to short-term or average wholesale prices.
- PPAs provide a volume as well as a price commitment – for most generators the preferred PPA has an unlimited volume, thereby passing balancing risk to the off-taker.
- Most PPA contracts have some means to incentivise forecast accuracy and delivery by the generator.
- Some are direct PPAs between generator and consumer, others can be 'sleeved' or virtual PPAs that have back-to-back contracts with an energy supply company that will also then provide the balance of energy not generated through the PPA (or sell excess energy).

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[125] Confusingly, all power trades including short-term bilateral trades can be referred to as a PPA. Here we are focused on long-term PPAs of one to 20-year terms including CPPAs. CPPAs normally refer to PPAs with an energy end user, as opposed to an energy supply company, but the term is not well defined.

PPAs are already widely used in the GB market, enabled by the current bilateral trading arrangements. It is difficult to give an accurate assessment of the number of PPA contracts in place,[126] and their pricing structures, but research carried out by Aurora Energy Research suggests that the GB PPA market has grown substantially since 2010 and may be second only to Spain in Europe with an estimated 14 GW (24%) of renewable capacity under PPA terms.[127] Combined with renewables under CfD contracts, this would suggest that a significant proportion of renewable projects are already under some form of long-term contract.

PPAs can provide the revenue security needed to enable developers to raise finance for investment in generation assets. This has been essential for those smaller and community-based projects for whom a CfD scheme may not be appropriate. As such, improving and expanding the PPA market should be a priority for forward-thinking market reform and will help reduce energy costs, reduce market volatility and encourage investment in low-carbon renewables.

Despite their advantages, the current long-term PPA market suffers from several limitations, including:

- **Lack of contract and price visibility**, affecting the system operator as well as efficient competition and price discovery.
- **PPA contracts that are complex and difficult** to set up for smaller consumers and generators.
- **Long-term contracts that require long-term creditworthiness,** which means that PPAs have been limited to corporations and other organisations with blue chip credentials or government backing; for example, large corporations, blue chip industries, larger energy supply companies, universities and local authorities.

Enhancing and developing the PPA market is a key item for progressive market reform. This may not require a significant change to existing market arrangements and may be best served by enabling the market to continue to innovate. However, it may involve nurturing and encouraging the market via a variety of regulatory and soft market interventions, for example:

- Providing better guidance and information to encourage PPA uptake.
- Encouraging and enabling public sector energy procurement.
- Increasing market visibility.
- Working with industry to develop PPA standards.
- Combining with retail market reform to incentivise energy supply companies to offer a range of PPA-supporting supply agreements and sleeving arrangements.

Ofgem could, for example, review the range of PPA products offered by energy supply companies, encouraging harmonisation in some areas and innovation in others. New entrants,

[126] A lack of market transparency and visibility is one of the current market weaknesses that a progressive reform programme must address.
[127] Aurora, 2022. Role of PPAs in the GB Power Market.

offering different off-take and supply arrangements, including local energy supply models, could be encouraged.

Going further, innovative PPAs with sleeving arrangements could form the basis for establishing local and sectoral 'green power pools'. For example, a collaborative sleeving pool for Bristol, a Celtic Sea power pool for the south west of England and South Wales, a power pool for the steel industry or one that underpins a housing association or a social tariff.

As a minimum, REMA must consider the potential impact that other market reforms would have on the private PPA market. For example, a shift to zonal pricing and centralised dispatch would impact all existing PPA contracts and could significantly inhibit PPA usage in the future.

F.4 Underwriting PPAs, shared sleeving and green power pools

The REMA consultation has pulled back from more ambitious options to underwrite PPAs or to go as far as to create green power pools that could support energy supply for particular sectors, regions or consumer groups. The argument put forward is that these are not interventions for national government to make, although REMA officials have stated that they are not against the market coming forward with new PPA or power pool innovations.

It is understandable that the REMA scope should focus on those areas where UK government policy intervention is needed. However, there is a risk that the review of market arrangements becomes too narrowly focused on reforms to government-backed schemes such as the CfD and CM. A progressive reform agenda would also include the wider market and how well the market is able to get low-cost energy to the consumer, target fuel poverty and support levelling up, while still accelerating low-carbon investment.

The potential to create a green power pool to support critical sectors like the steel industry has been well documented.[128] Regen has also been working with a number of local authorities to look at how power pools or collaborative sleeving arrangements could be established to ensure that localities are able to procure locally generated renewable energy under competitive long-term contracts.

Power pools can overcome some of the limitations of individual PPAs by creating economies of scale, risk sharing and credit worthiness. They can also allow demand consumers to more easily aggregate their demand flexibility, making them an attractive proposition for energy supply companies and the provision of constraint management services. A localised approach to green power pools could be implemented to bridge the generation gap between a CfD and Smart Export Guarantee.

[128] See for example New Civil Engineer 2024 or Steel Orbis 2024.

A green power pool or shared sleeving pool could, for example, be set up to allow councils and public sector organisations to buy renewable energy on a long-term contract, while also aggregating their demand flexibility (see for example Bristol Collaborative Sleeving Pool).

In another example, stakeholders in Cornwall are looking at ways in which the expected abundance of offshore wind from the Celtic Sea can be supplied to local businesses, housing associations, communities and fuel-poor customers as part of a Celtic Sea power pool.

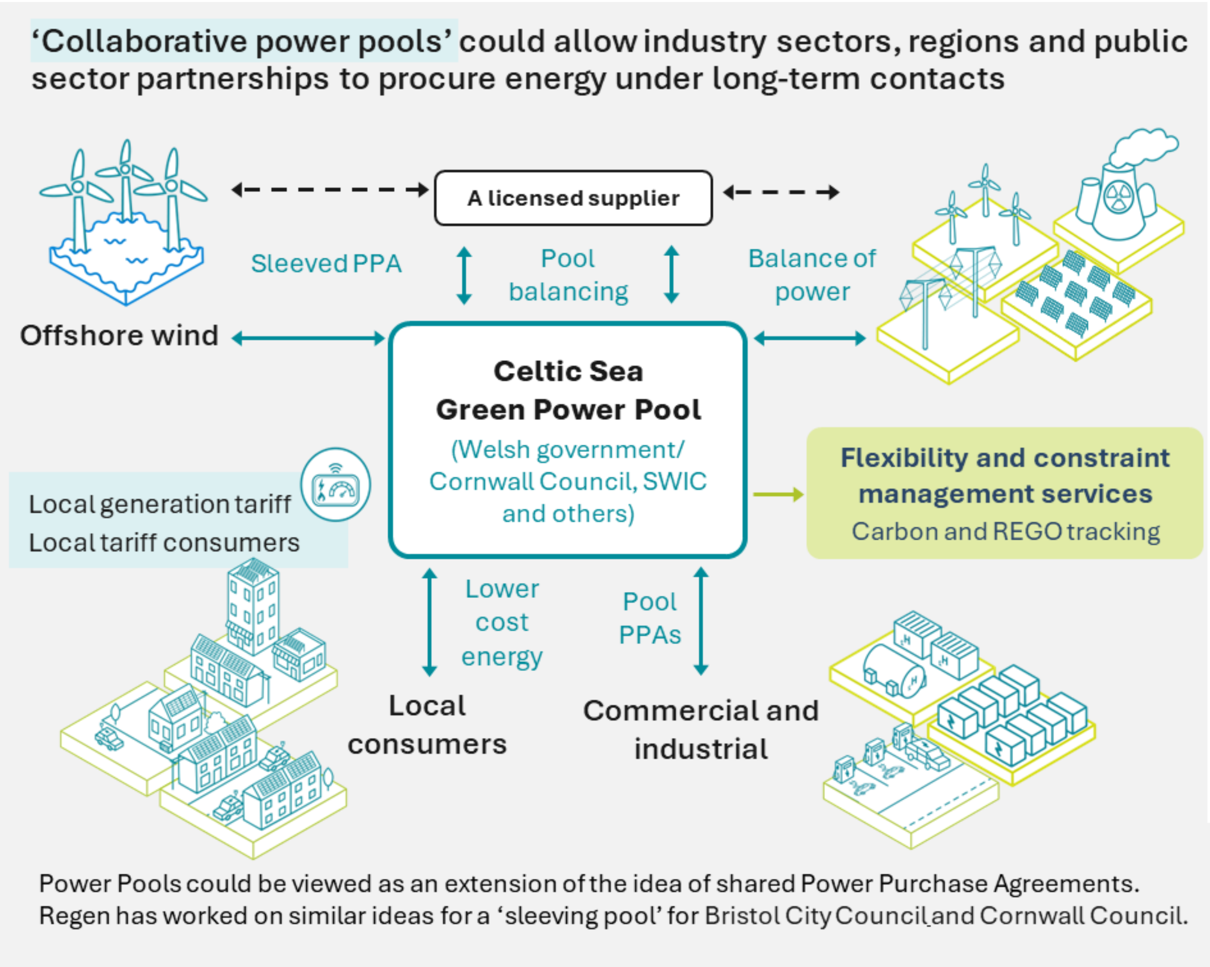

Figure 26. Outline framework for a Celtic Sea green power pool.

Theme G

A just transition for the consumer, communities and the fuel poor

Coming out of the 2021-2023 energy crisis, it is understandable that REMA should focus on the challenge to transfer the value of lower-cost renewable energy to the consumer. However, while this is a critical challenge, it should not be the only measure of consumer or societal value. Stakeholders, including community groups and local authorities, that Regen has engaged with on the subject of market reform have consistently stated that they are interested in a wider set of consumer and social value benefits.

To capture some of these stakeholder views, Regen submitted an additional response to the REMA consultation on behalf of over 50 local authorities that are currently participating in the Thriving Places programme[129] (part of the Innovate UK Net Zero Living programme).

The priorities identified by these stakeholders included how market and revenue support reforms can:

- **Be used to alleviate fuel poverty and to address the growing problem of energy inequality,** especially for those consumer groups such as tenants, whose energy supply choices are limited, as is their ability to access new technology and new energy services and to participate in the energy market.
- **Encourage greater levels of community and local energy ownership**, and specifically enabling smaller projects at community scale to access the market and secure finance.
- **Enable local energy supply and the ability of consumers to procure energy from local sources** at a fair price that a) provides a viable return for local generation b) incentivises greater use of local energy and c) recognises the energy system value of local energy supply.
- **Enable consumer to participate in the market in a meaningful way** and in a way that gives consumers agency to provide energy system services, such as flexibility, in a way that is fair to themselves and to other consumers.

[129] The Thriving Places programme support to local authorities, their partners and communities to overcome non-technical systemic barriers to the scaling and adoption of net zero solutions.

- **Provide incentives to increase the regional and local socio-economic** benefits that will come from the energy transition, through better regional planning, infrastructure investment, supply chain, skills and employment.

It was notable, for example, that at the Energy Security and Net Zero Select Committee hearing on 7 February, MPs discussing 'locational' pricing were, in fact, more often asking for measures to support local markets and local energy supply.[130]

In Regen's view, this broader measure of societal value is critical to maintain and garner support for the net zero energy transition. In our experience, society will only support the energy transition, and bear the cost of its implementation, if the transition is demonstrably fair and there are tangible benefits at a local level.

Theme G: Summary reform agenda

Progressive Reform Agenda	
G: Markets that work for the consumer: Ensuring a just transition – supporting communities, local energy and the fuel poor.	
G1	Embed wider consumer interests at the heart of market reform, ensuring that reform is not only about bringing bills down, but also about developing community energy, tackling fuel poverty, a just transition and supporting local economies.
G2	As a minimum, assess the impact that any proposed market reforms will have against wider value criteria, including on fuel poverty, distribution of benefits and costs between consumer groups, community energy ownership and the provision of local energy.
G3	Enable positive participation in flexibility markets for both domestic and industrial consumers, to allow them to provide system services including local constraint management and flexibility services.
G4	Review the operation of the PPA market and consider whether additional revenue support is needed to (for non-CfD projects) to provides long-term contracts for local clean power at a level that recognises the wider social and economic benefit of community and local energy supply schemes.
G5	Encourage innovation and the provision of new supply contracts that will support the creation of green power pools, local generation tariffs and collaborative sleeving PPAs.
G6	Review the merits of different local energy supply models with an objective to encourage greater use of local energy supply, community energy and ownership as part of a wider energy devolution agenda.

[130] See Regen's written response to the select committee hearing A flexible grid for the future.

G7	Reconsider how wholesale market arrangements can provide the basis to support targeted social tariffs and other measures to alleviate fuel poverty and protect consumers from future price shocks. Even if a social tariff is put on hold, market reform should include a blueprint of how fuel poverty could be addressed in a future energy crisis.
G8	Reform of the levy control framework and how levies (including the expansion of CfDs) are recovered from consumer bills.
G9	Increase participation of consumer representatives in future REMA design development, and increase the level of integration and coordination between wholesale and retail market design.

G.1 Enabling local energy supply

Power pools and collaborative sleeving schemes are just two examples of innovation that is needed to enable energy to be supplied locally. Local energy supply is one of the most frequently cited objectives for community energy groups and, in Regen's view, is one of the most important factors to secure community support for the energy transition and to ensure that the energy transition benefits localities and regions. Local supply schemes could also provide a route for communities and consumers to participate in the energy market and support the energy system by, for example, unlocking higher levels of demand flexibility and to participate in local constraint markets.

Regen has been working to trial and develop local energy supply solutions for over a decade.[131] Options for local energy supply, which could be implemented within the existing wholesale market arrangements, have not featured strongly in the REMA consultation. Local energy governance and the provision of local flexibility solutions are, however, set to become more important as Ofgem implements its plans for Regional Energy System Planners and creates new institutions for local energy governance. Given the ever-increasing role that local and small-scale generators are having in the energy transition, we would encourage the government to consider how local renewable pooling arrangements, supported or initiated by local authorities, could be integrated into the wholesale market.

Local power and community ownership features heavily in the 2024 Labour manifesto and its plans for Great British Energy.

[131] See, for example, our thought leadership analysis on local energy supply options, first published in 2013.

Local power generation is an essential part of the energy mix and reduces pressures on the transmission grid. Labour will deploy more distributed production capacity through our Local Power Plan. Great British Energy will partner with energy companies, local authorities, and co-operatives to install thousands of clean power projects, through a combination of onshore wind, solar, and hydropower projects. We will invite communities to come forward with projects, and work with local leaders and devolved governments to ensure local people benefit directly from this energy production. – **Labour Manifesto, 2024**

G.2 Consumer-centric flexibility that also works for the energy system

The energy market is changing rapidly. The GB market is already seeing more price volatility in the wholesale market, including periods on windy and sunny days when prices have fallen to near zero and even negative, and others where we have seen peak wholesale prices regularly reach over £400. This highlights that the market is already sending strong time-of-use signals and this has supported an increase in agile and flexible tariffs.

As the UK deploys more renewable energy, alongside nuclear, the market will become more volatile, with significant periods of excess energy (where curtailment of available renewable generation is needed) when electricity prices may drop to near or below zero, and periods with very high prices driven by the need to bring on higher-cost back-up and standby generation.

Price volatility, and energy curtailment, is an issue for the market and for the consumer, but also an opportunity. There are lots of ways in which the market can respond (over time) to take advantage of changing energy prices – through storage, interconnectors, production of hydrogen, etc, as well as by harnessing the demand flexibility of both domestic and commercial consumers.

A key to successful demand-side response is to get consumers engaged in the system and to respond to an **appropriate level** of market price signal, but there must be a balance between harnessing consumer flexibility and putting consumers in a position where they may be disadvantaged, treated unfairly or otherwise exploited. There must, therefore, be a balance between consumer price-risk exposure and protection of those consumers that are unable to respond to price signals. It's also important that all consumers view the system as being fair without arbitrary advantages and disadvantages, or particular consumer groups who are both gaining from the net zero transition opportunity and profiting from its challenges.

An additional consideration is that very strong price signals which benefit one part of the energy system (e.g. to alleviate transmission constraints) may in fact cause an overresponse that adversely affects other parts of the energy system (e.g. increasing constraints on the low voltage network).

The government and Ofgem have previously published a number of policy documents on the subject of smarter energy systems and flexibility, including the 2017 and 2021 Smart Systems and Flexibility Plan. This document, which is still current in many ways, provides a wider perspective on the need for flexibility in a net zero system.

The second REMA consultation's focus on flexibility, though, has been mainly around support for investment in flexibility assets, reform of the BM and improving temporal signals – for example, a reduction in the duration of settlement periods. While these are important areas of reform, there has not been as much focus within REMA on how markets engage with consumers, and how markets can encourage consumer participation in the provision of demand-side flexibility in a way that supports the energy system while still being fair and equitable across consumer groups. Where demand flexibility has been discussed, it has mainly been in the context of nodal LMP and whether consumers should, or should not, be exposed to highly volatile locational price signals.

A progressive market reform agenda must include a wider consideration of how consumers will interact with markets in the context of the rollout of low-carbon technologies and how flexibility can be harnessed to provide system services without penalising those consumers who may not be in a position to participate because of their energy usage, access to smart technologies or barriers such as network constraints.

As a point of principle, Regen has argued that:

1. The wholesale market is the appropriate channel to deliver temporal price signals where those price signals reflect the overall GB market supply/demand balance and marginal cost of energy.

If price volatility as being driven by **the overall supply/demand balance across the market**, then there is a good argument that demand and generation should be exposed to that price signal. This is on the basis that all consumers are in the same market and are supporting the same energy transition through their contributions to the investment in new energy systems assets and infrastructure, and revenue support.

There is then a question of whether all consumers would wish to be exposed to time-of-use price signals and the choice that they have to select a tariff with more, or less, price exposure. Energy supply companies also have a choice to what degree they want to trade in short-term markets, and expose their customers to temporal price signals, or hedge against price volatility through longer-term PPAs and forward trading. Regulators may also need to ensure that tariffs are fair between consumer groups and take steps to protect consumers who are vulnerable or in fuel poverty.

2. The wholesale market is not, however, the appropriate channel to deliver signals related to energy system requirements such as distribution or transmission constraint management.

Network constraints, if reflected in wholesale prices via locational pricing, would potentially send very volatile and extreme price signals that would affect all consumers, whether they are in a position to respond or not. This has been described as a postcode lottery, but could be more accurately described as a network constraint lottery.

This would be unfair and inefficient for several reasons:

- Locational wholesale pricing would create a disparity in energy prices across locations (zones or nodes) based on the happenstance of network investment and occurrence of transmission constraint.
- Consumers within constrained areas may receive very strong price signals to which they are unable to respond – potentially increasing whole-system costs and frustrating consumers who want to respond to a transmission-level LMP signal but are unable to do so.
- Transmission nodal or zonal wholesale signals may exacerbate distribution-level constraints, leading to network operators needing to limit the ability of customers to respond to those signals to protection the distribution network.
- A subset of consumers in a generation-constrained zone may enjoy lower electricity prices, requiring a higher level of subsidy under RAB or CfD schemes, paid for by consumers in other zones, leading to an unfair value transfer between consumers.

Where flexibility is needed to provide system benefits or deal with issues like network constraints, Regen has proposed that flexibility should be harnessed via more targeted flexibility markets and service offerings. In other words, we should incentivise those demand consumers that can offer flexibility to do so on an opt-in basis, without penalising the entire consumer group. Demand-side flexibility to support system outcomes would be better harnessed and targeted through specific flexibility service markets such as the flexibility auctions that are currently in common use by distribution networks.[132] The ESO is already running trials for local constraint markets, which could be extended and refined.[133]

The key advantage of this approach is that flexibility can be offered by those consumers that are in a position to respond to targeted signals, and can be better coordinated between transmission and distribution networks to avoid sending conflicting signals.

To minimise the cost impact on wider consumer bills, demand flexibility would need to be competitive with other forms of flexibility and constraint management solutions. Again, this is an area of strong overlap and integration between wholesale and retail market reform.

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[132] Distribution networks have already contracted several GW of flexibility capacity including demand-side response. See for example: UKPN and Octopus Energy 'Power Ups'.
[133] See for example the ESO's current trial with PICLO and Simon Gill's paper on constraints.

Box 3. Note on shielding consumers in a locational wholesale price market

A note on shielding consumers in a locational wholesale price market
In response to challenges about fairness and consumer impacts, proponents of locational pricing have suggested that (mainly domestic) consumers could be protected from price differences and volatility through various forms of 'shielding'. For example, by some form of redistribution to equalise bills or rules that would prevent suppliers from charging different prices to customers based on their location. While in theory this can be done, in reality it will be extremely difficult to shield customers from locational signals without either incurring an extremely heavy administrative burden or introducing other market distortions. Shielding the demand side also significantly reduces the benefit and rationale for locational pricing. It is also impossible to develop a shielding strategy without a full retail market design and without the ability to anticipate how retail suppliers will respond. Some shielding solutions also rely on there being a central dispatch arrangement with mandated day-ahead market. Conceptually, if locational pricing introduces greater price volatility and differentials between locations, and potentially greater balancing risk, then, one way or another, these risks/costs/benefits will be passed through to consumers. This pass-through could be explicitly in the tariff or in the way suppliers will sell energy to different customer groups depending on their location and profile. It is notable that discussions around shielding tend to focus on how the market can mitigate locational price differentials for the 'typical' or average customer. This is important, but ignores the question of fairness between different customer groups within each location, and specifically the question of equity between those customers that are able to take advantage of locational price signals and the very many who, for a variety of reasons, will not. For a more honest and constructive debate, it would be better to start with the presumption that consumers will not be shielded from locational prices and then to understand what impact this would have across all customer groups.

G.3 Protecting the fuel poor – green social tariffs and other measures

As the energy crisis passes, and electricity prices fall, the impetus to address fuel poverty, for example through a targeted social tariff, has receded. An explicit social tariff was not included in the 2024 Labour manifesto, although there is a general commitment to tackle energy bills. It is, however, very likely that a new energy crisis will occur and so it would be prudent for policymakers to consider how market arrangements may support, or fail to support, fuel poverty actions now and in the future. Whether this is through the continuation of an energy price cap or some other, more targeted, solution such as a green social tariff, remains a key question for the reform agenda.

How the wholesale market arrangements might support a social tariff(s) or other measures to tackle fuel poverty has not been included in the REMA scope. It could be argued that this is a matter for retail reform and/or for the regulator to consider as part of its future plans for the tariff cap. There are, however, points of overlap and integration between the provision of a social tariff and how these schemes are supported by the procurement of electricity in the wholesale market.

There are a number of ways that a social tariff could be supported through the procurement of renewable energy under long-term contracts. For example:

- UK or local governments could create their own energy supply company for fuel-poor customers. This could be part of an independent 'GB/region x Energy Company' or a 'white label' arrangement administered by one or more energy supply companies.
- The government (or an agent, like Great British Energy) could enter into long-term PPAs for renewable energy and trade these with energy supply companies that are providing a social tariff.
- The government (or an agent) could underwrite long-term PPAs entered into by energy supply companies, local authorities and other third sector organisation to create their own social tariffs or local supply markets.
- Social tariffs could be supported at a more local level (region or local authority) through the creation of green power pools.

G.4 Reform of the levy control framework and how policy costs are recovered

It has been widely recognised that the current approach, whereby environmental levies (including CfDs) are recovered from electricity bills, is not sustainable and is producing a significant market distortion that is slowing down the transition to low-carbon technologies and, in particular, the electrification of heat.

Reform of the levy control framework and how levies are recovered It has been widely recognised that the current approach, whereby environmental levies (including CfDs) are recovered from electricity bills, is not sustainable and is producing a significant market distortion that is slowing down the transition to low-carbon technologies and, in particular, the electrification of heat.This environmental levy distortion has been recognised by the government and regulator in both the 2020 Energy White Paper and the 2022 Net Zero Energy Strategy. There have been a range of solutions put forward, including the creation of a new green gas levy, equalising levy payments between gas and electricity based on carbon emissions, or transferring a portion of the levy to general taxation. None of the solutions would be easy to implement, as they are bound to create winners and losers, but in the long term the price distortion created by the levy needs to be addressed. This is particularly the case if REMA recommends the extension of CfDs as the main revenue support scheme which will rely on the use of the levy, and if the levy approach continues to be used to support cross-vector decarbonisation in areas like heat and energy efficiency.

G.5 Consumer engagement and reform governance

Is has been noted that the level of consumer focus and engagement with consumer groups has been limited throughout the REMA consultation period. There has been an 'end user' forum, which has met on a number of occasions, but overall the consumer impacts of market reform, including the potential distributive impacts of zonal pricing, have not been fully explored. There has been a rather technocratic assumption that price volatility to incentivise consumer response is a wholly good thing, whereas there needs to be a debate about how consumers participate in the market and the extent to which all consumers should be exposed to price signals. The issues around consumer shielding from price signalling hasn't been explored and has, arguably, been avoided. See Box 3.

In addition, proposals for retail reform and wholesale market reform have been developed as separate programmes. In a number of areas, wholesale market reform options will have a direct impact on retail markets and are predicated on assumptions about how energy supply companies will respond to wholesale markets. Regen has suggested bringing the two reform programmes together into a single programme – however, if this is difficult from a timing and delivery perspective, there at least needs to be a coordinated approach and overlapping governance structure. It is also noted that retail reform seems to be progressing at a far slower pace than REMA and it is unclear whether this is a deliberate strategy in order to sort out wholesale markets first, or just a result of resource constraints. Either way, it is essential that retail and wholesale market designs are aligned and properly tested with consumers.

More broadly, the governance and decision-making arrangements that sit behind REMA need to be reviewed. Regen has participated on a number of working groups and expert panels, but it is not clear how decisions are being made and evidenced.

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