CONSULTATION RESPONSE

Review of Electricity Market Arrangements - second consultation document

Response from Regen

07 May 2024

About Regen

Regen provides evidence-led insight and advice to transform the UK's energy system for a net zero future. We know that a transformation of this scale will require engaging the whole of society in a just transition. We have 20 years' experience in transforming the energy system for net zero and delivering expert advice and market insight.

Regen is also a membership organisation, managing the Regen members network and the Electricity Storage Network (ESN) – the industry group and voice of the grid-scale electricity storage industry in GB. The Electricity Storage Network has provided a separate REMA consultation response to ensure clarity of message. In total, we have more than 150 members who share our mission, including clean energy developers, businesses, local authorities, community energy groups, academic institutions and research organisations across the energy sector.

Regen hosted a REMA engagement event in April 2024 attended by over 120 energy industry delegates. The points made in that event (including several polls taken) – as well as feedback from bilateral conversations with members and engagement with the Department for Energy Security and Net Zero (DESNZ) team – have fed into this response.

This response represents the views of Regen, however, it is based on extensive practical experience and follows Regen's input into conversations on energy market reform, where we have previously highlighted the need for radical reform of the electricity system and markets to unlock the accelerated scale and pace in renewable energy deployment needed to achieve net zero. Our response also benefits from input from our members.

Continuing engagement

Regen is keen to continue its engagement with the Department for Energy Security and Net Zero team in the development of the GB electricity system and market arrangements.

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Executive summary

Regen welcomes the publication of the second REMA consultation as an important milestone towards the development of an efficient GB electricity market. Regen greatly appreciates the work done by the REMA team and the progress that has been made. Our team has found the level of engagement and openness of the REMA team very beneficial to help us provide input, to learn from others and to formulate our ideas.

The narrowing of options is broadly welcomed, including the decision to drop nodal Locational Marginal Pricing and a Split Market option.

In most key areas we are supportive of the overall REMA direction of travel and the options that have been proposed. However, we believe that **the benefit case for zonal pricing has not been made** and that the design options for zonal pricing have not been clearly defined. Our engagement with industry suggests that this view is shared by the majority of REMA stakeholders. Given the weak benefits case, and the implementation and investment risk during a period of energy transition, we recommend that DESNZ drops the zonal pricing option to reduce investor uncertainty and to focus resources on other, more effective and deliverable, reform solutions.

Should DESNZ decide to keep zonal pricing as an option, we consider a further design phase and consultation should be held before any decision is made. This will entail conducting a comprehensive evaluation of design options, cost-benefit analysis and assessing compatibility and legacy impacts associated with zonal pricing.

Regen's view is that the benefits of an efficient energy market, and REMA's four challenge objectives, can be **better and more quickly achieved through a programme of Progressive Market Reform,** based on the foundation of the current national trading market arrangements.

We have set out some of the key pillars of a **progressive market reform agenda** in our consultation response and will shortly publish a position paper on this subject.

Regen's REMA response highlights

1. We welcome the decision to drop nodal LMP and Split Market.
2. We recommend now **dropping zonal pricing**, or relegating this to a counterfactual, and instead focusing resources and effort on developing a progressive reform programme to enhance the national trading market.
3. If DESNZ decides to retain zonal pricing as an option there is an urgent need to:
   - Clearly define a set of viable design options – including zones and dispatch
   - Present a more **robust and credible benefit case with realistic assumptions**
   - Present legacy arrangement options and associated costs
   - Assess and present the **investment risk and migration** options (and its costs)
   - Set out how forward trading and risk hedging will be supported (and its costs)
   - Address the implications for consumers and distribution-connected assets
   - Present a credible implementation plan, timetable and costs
   - **Fully engage industry in any decision and conduct a further consultation**
4. There are significant opportunities for operational reform within a **progressive reform programme** including in areas such as; constraint management, the balancing mechanism and ancillary markets and the operation of interconnectors.
5. The **issue of locational signalling for investment and asset siting can be addressed** through better strategic planning and more direct locational signals through, for example, network charging, connections, leasing/planning, balancing and flexibility markets and revenue support schemes.
6. We support the proposals to **retain and enhance the use of CfDs** and **Power Purchase Agreements**. Both can play a complementary role to accelerate investment and pass the benefits of low cost renewables to consumers.
7. **REMA could be more ambitious** in other aspects of consumer value including reforms to help to address fuel poverty, fairness for consumers and to promote local energy supply and local Green Power Pools.
8. **We agree that a deeming option for CfDs could reduce investment risk** and market distortions and should be developed with consideration of its potential unintended market impacts, including for other generators and flexibility providers.
9. We are supportive of the proposal to take forward a **single Capacity Market auction with multiple clearing prices and minima** procurement target for desirable characteristics, provided it is based on an ambitious low-carbon flexibility target. More detail is needed on how this would work in practice.
10. **More needs to be done to incentivise** the conversion of fossil fuel plants to low-carbon technologies and to manage the decommissioning of unabated fossil plants outside the market while ensuring energy security.

Section 1: Regen consultation response

As the UK advances towards net zero, well-structured and designed markets become an essential tool in reaching energy policy objectives – driving investment in the energy transition, ensuring energy security and keeping consumer costs as low as possible.

As a successor to 2013's Electricity Market Reform (EMR) package, and the 2001 and 2004 NETA and BETTA reforms before that, the Review of Electricity Market Arrangements (REMA) programme plays an essential role in providing the foundation for GB's future energy system.

1.2. Progress since the first REMA consultation

Regen recognises that significant work has been undertaken by the team at the Department for Energy Security and Net Zero (DESNZ) across the REMA programme, including extensive stakeholder engagement, and we are pleased to see that the second consultation has narrowed down the options for reform.

Regen especially welcomes the government's decision to drop both the nodal Locational Marginal Pricing (LMP)[1] and Split Market options, agreeing that neither would aid GB's energy sector shift to net zero and would carry too much investment and implementation risk.

Regen also welcomes the recognition and increased focus on developing a more realistic counterfactual based on a national pricing model. This 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.

"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."

DESNZ, REMA: second consultation

[1] Nodal was dropped *"due to the impacts it would have on investor confidence and the deliverability of our* [DESNZ] *2035 decarbonisation targets".*

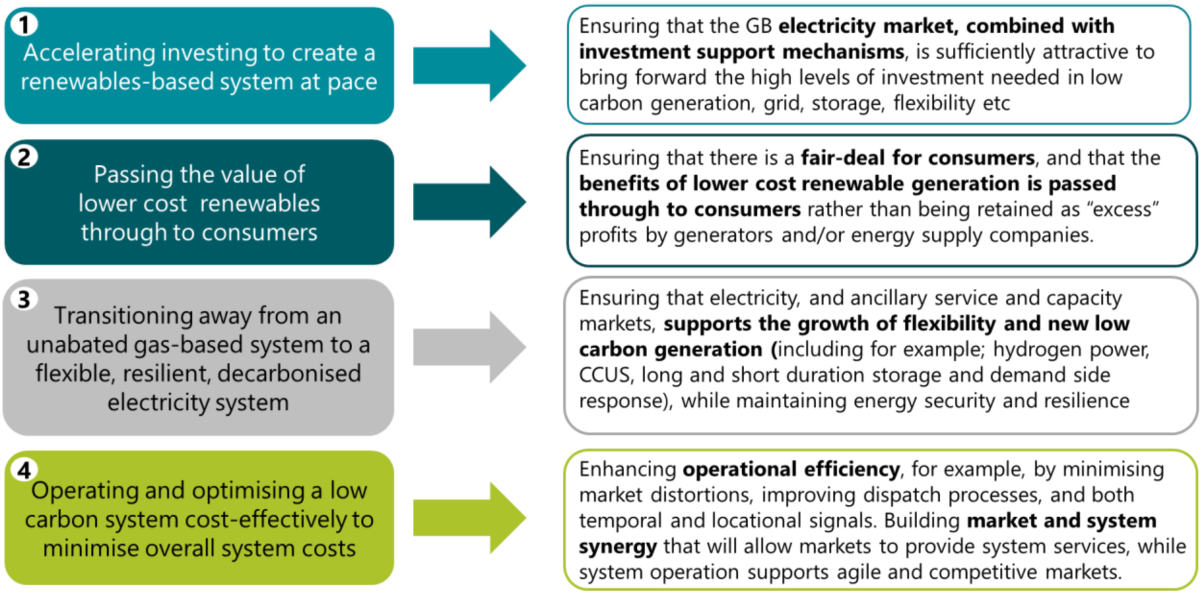

Figure 1**: Regen supports the four key REMA objectives**

Regen response highlights – REMA options and objectives

Regen welcomes the second consultation and **the narrowing of options** that have been presented.

Regen supports the **dropping of nodal and Split Market** options.

Regen supports the **four key REMA objectives**, although in some areas we believe the scope of the objectives could be widened to address progressive reform objectives including addressing fuel poverty, just transition and fairness between consumer groups more directly.

There is a need to **ensure that the REMA work is aligned** with wider reforms in the areas of strategic planning, retail reforms and the accelerated delivery of a net zero power system.

Overall, there is a **need for far greater detail and analysis of the design options**, especially around zonal pricing, centralised dispatch, Capacity Market minima and CfD deeming.

The analysis of **legacy arrangement and the compatibility of design options is still underdeveloped** and probably reflects the fact that several options are still in play and have not yet been defined.

It would be difficult to go from the second consultation to final design decision and impact assessment without a further round of design, engagement and consultation.

1.3. An agenda for Progressive Market Reform

The initial phase of the REMA consultation has been marked by a vigorous debate over whether the GB electricity market requires a radical overhaul or incremental reforms.

Whilst we endorse the case for change set out in the REMA consultation, we believe that the case to radically redesign the GB market has not been made. Our analysis suggest that the key elements of our current national market based on bilateral trading, decentralised dispatch and a secondary balancing market are robust and could form the basis for a reformed energy market.

The recognition by both Ofgem and DESNZ that there is a need for a progressive counterfactual, to confirm whether greater benefits could be achieved through a package of policy reforms to existing national market arrangements is an important conclusion currently missing from the policy debate.

There is strong evidence that most REMA stakeholders would prefer an incremental package of reform. At a recent REMA event hosted by Regen on 22 April 2024, approximately 66% of participating delegates, as revealed by a poll, favoured incremental reforms (Figure 2). Conversely, only 17% endorsed a more radical option, such as zonal pricing. This aligns with responses from the initial REMA consultation and is indicative of the broad consensus within industry and among wider stakeholders.[2] Similar sentiments have been reflected in surveys conducted by other organisations, such as Cornwall Insights' industry survey 'LMP is not the answer'.[3]

Following two years of reform consultation, the predominant stance among industry and investors favours incremental changes over radical options. This perspective is vital to consider in any future evaluation of zonal pricing.

"*However, this kind of market reform comes with potential risks to investment and distributional impacts on consumers. It is therefore important to explore the counterfactual of improving locational signals under the current single price model through a possible combination of better spatial planning, anticipatory network investment and reforms to CfD design, network charges, access arrangements and balancing markets. This "reformed national market" should serve as the counterfactual to locational pricing options in determining whether or not the latter would be a desirable policy*."

Ofgem Assessment of LMP.[4]

[2] 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.

[3] Cornwall Insight, 2022. "LMP is not the Answer".

[4] Ofgem, 2023. Assessment of Locational Wholesale Pricing for GB.

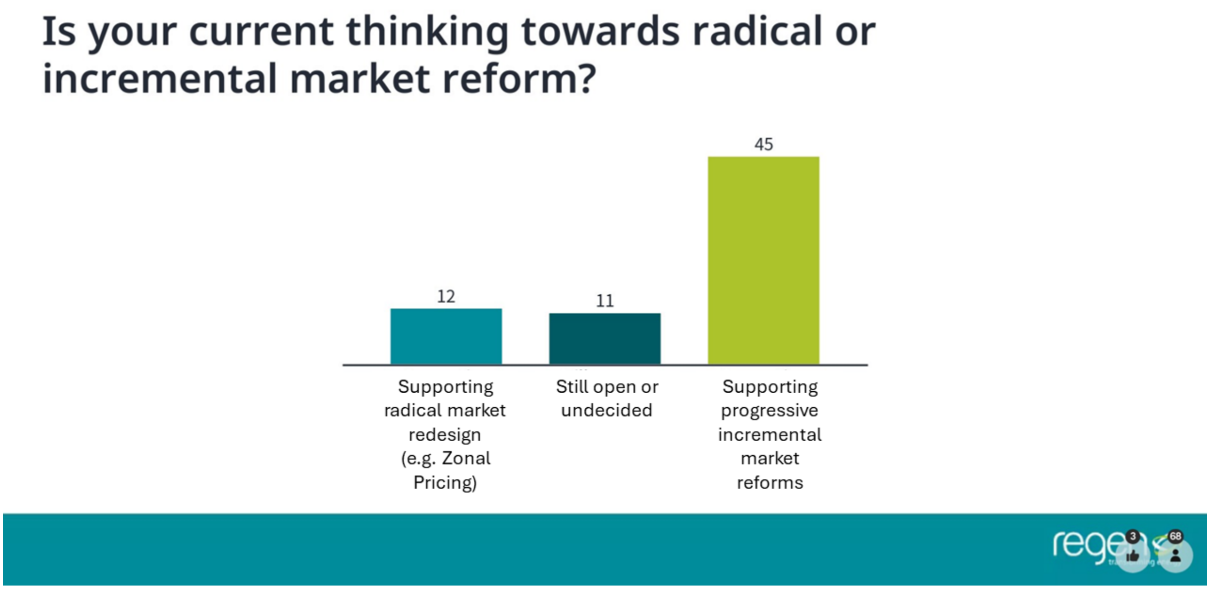

Figure 2**: Participant responses on a progressive or radical market reform.**
Source: Regen REMA consultation event 22 April 2024

As an alternative Regen has been developing a set of reform proposals which would build on existing market arrangements and offer a far quicker, and less risky, route to market reform. We have called this an agenda for **Progressive Market Reform.**

Our assessment of the REMA case for change and the four key REMA objectives is that a programme of progressive market reforms could:

- Meet the overall objectives set out by the REMA programme.
- Match or exceed the benefits claimed for LMP and other radical reform options. This includes benefits from a) optimal siting of assets, b) operational efficiency, and c) value transfer benefits where these represent a genuine transfer of producer surplus.
- Secure benefits in key areas such as constraint costs, interconnector operations and balancing costs within a relatively short timeframe, compared to implementing more radical changes.
- Provide an achievable and deliverable pathway to market reform that would be ambitious but sustainable.
- Build a consensus of support across the industry and with wider consumer stakeholders, which will be essential to implement market reform.
- Maintain momentum towards the delivery of the UK's net zero and energy security strategy.

A progressive market reform agenda does not mean maintaining the status quo or a business-as-usual approach. Progressive market reform would bring a significant and meaningful change to the electricity wholesale market, revenue support arrangements and ancillary markets.

Regen response highlights – Progressive Market Reform

Regen is pleased that DESNZ has committed more resource and focus in the second phase of the REMA consultation to develop **a coherent and realistic alternative incremental reform package** based on a national market model.

We are still concerned, however, that the national market reform programme is not well articulated in the current consultation and is being viewed as a counterfactual rather than a preferred package of reform. We suggest that **priorities should be reversed** with a clear focus on incremental reform that can be achieved within the existing market arrangements and then a counterfactual based on zonal pricing.

Regen believes that an ambitious agenda for **Progressive Market Reform** can best achieve the objectives set for REMA while still maintaining the investment and momentum needed to deliver the UK's energy strategy.

Regen will be publishing a position paper on Progressive Market Reform shortly.

1.4. Response on zonal pricing

Design clarity and zonal options

The design and options for zonal pricing are extremely unclear. Although options have been identified at a high level, they have not been defined in the consultation.

As DESNZ acknowledges, zonal pricing could come in a variety of options, some of which would retain many features of the current market whilst others would require an extreme market redesign. Regen's concern that the zonal pricing model is still unclear has been reflected in feedback received from our members and industry colleagues. Our REMA event survey showed that only two out of 73 delegates polled felt that the zonal design option was clear from the information provided, the majority thought it was unclear (Figure 3).

"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 Review of Electricity Market Arrangements Options Assessment 2024

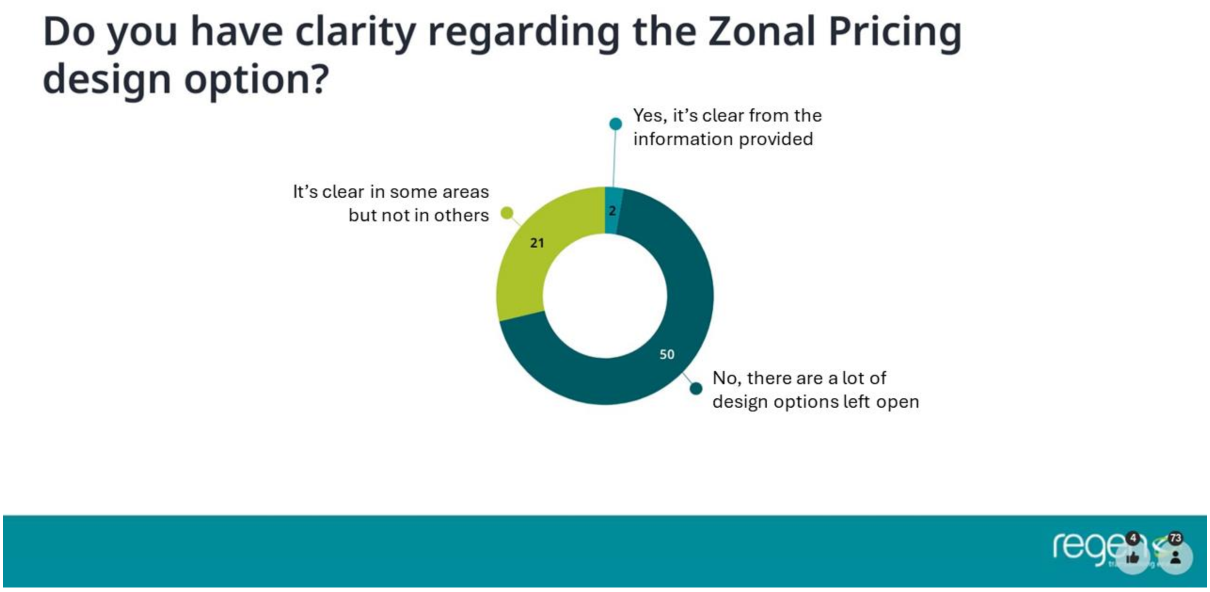

Figure 3**: Participant responses on zonal pricing design option clarity**
Source: Regen REMA consultation event 22 April 2024

Regen understands that more work is being conducted by the REMA team to develop the zonal pricing option. However, it is currently extremely difficult to assess the impact of zonal pricing, or even judge how such a market design would be implemented within the context of the current GB market and net zero transition.

Every aspect of the zonal design requires more detail, but especially:

- The definition of zones and how zones might change over time.
- Dispatch arrangements and whether zonal would include a shift to centralised dispatch (which would almost certainly be the case).
- Demand exposure to zonal price signals and how this would be implemented in retail markets.
- The distributional impacts of zonal pricing and its fairness between zones and between consumer groups within zones.
- Arrangements for forward trading, Financial Transmission Rights (FTR), markets and hedging.
- CfD design including reference price, negative price rules and alignment with CfD REMA design options including deeming.
- All aspects of how zonal pricing would impact distribution network connected assets and consumers.
- Interaction and integration with EU markets and interconnection.

Therefore, if DESNZ is minded to retain zonal pricing as an option, a more detailed design needs to be presented to market stakeholders and a further consultation undertaken. There is insufficient detail and clarity of design to move to a decision-in-principle to adopt zonal or proceed with an impact assessment, as suggested for the REMA programme's next phase.

Industry stakeholders have also expressed a preference for a more detailed design of zonal options before any decision is taken to proceed with zonal pricing (Figure 4).

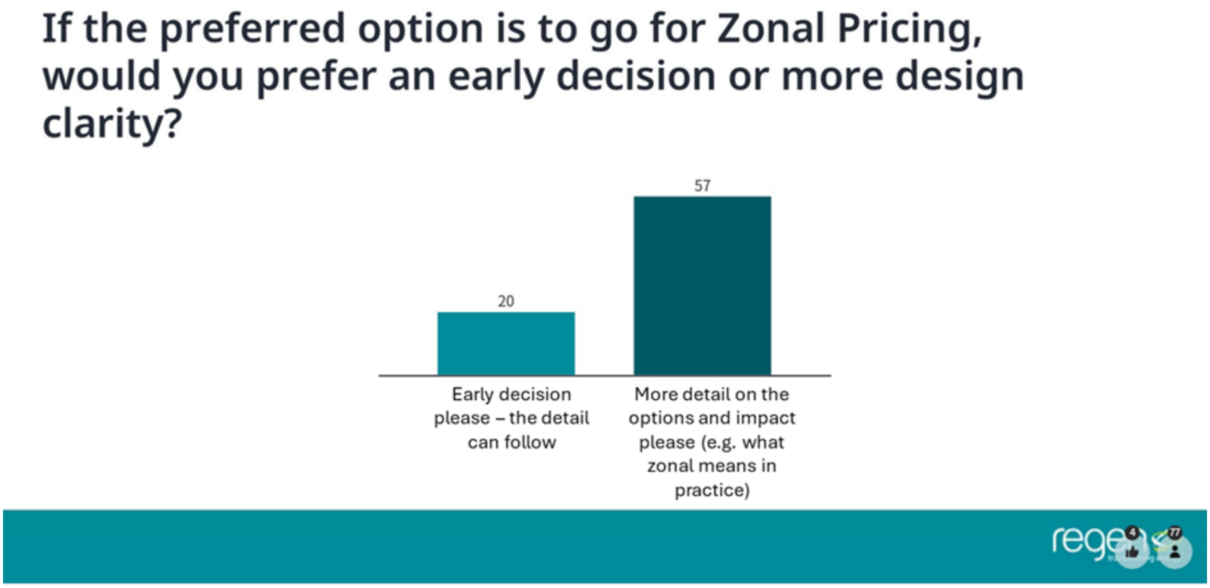

Figure 4: **Participant responses on the next steps for decision-making on LMP**
Source: Regen REMA consultation event 22 April 2024

The zonal pricing benefit case is extremely weak

The business case that has been presented for zonal, based on the analysis conducted by LCP Delta/Grant Thornton,[5] is extremely weak, reflecting a set of hypothetical assumptions that could easily be challenged. Benefits claimed would also be quickly eroded by an increase in investment risk, leading to higher costs of capital, delayed projects and other implementation and energy system costs that have not been quantified.

The REMA consultation document highlights both the potential benefits and risks of a zonal market design, while the analysis provided by LCP Delta identifies a range of system benefits of between £5.2-£15.5 billion for a zonal model over a 20-year period.[6]

It is understandable that it has been difficult to produce a more robust benefit case for zonal pricing. Several academics have commented the evidence case behind locational marginal pricing is extremely difficult to quantify.

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

[6] £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.

“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.”

Prof. Michael Pollitt, Cambridge University.[7]

It is important to note that LCP Delta/Grant Thornton has acknowledged the limitations of their assessment and have included a number of caveats in their report. LCP Delta has also highlighted that the benefit case would be eroded by an increase in the weighted average cost of capital of 0.3-0.9 percentage points[8] a figure that is well within industry expectations of the impact of zonal pricing.

The locational siting benefits also hinge on optimistic assumptions regarding a large-scale relocation of offshore wind from Scotland and the North Sea to the south coast of England. This is despite resource limitations, marine spatial constraints and port/supply chain challenges.

“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 March 2024 (report for REMA team on zonal LMP)

Regen has asked DESNZ for access to more of the background assumptions and data behind the modelling, including the re-siting of generation assets and modelling of interconnectors. Unfortunately, this information has not been provided in time to inform the consultation response and, therefore, the ability of stakeholders to properly interrogate and assess the benefit case has been limited.

Based on our reading of the report that has been provided, we have identified several problematic assumptions and limitations of the zonal business case. These include:

- **Use of scenarios for generation deployment and network infrastructure that are not aligned,** consequently overstating constraint costs and the benefits of zonal. Re-running the model with a different net zero scenario, aligned with an updated network investment plan, would significantly change the benefit case.

[7] Michael Pollitt, Cambridge University, 2023. Locational Marginal Prices (LMPs) for Electricity in Europe? The Untold Story.

[8] Moving the benefit case to an increase in system cost of £2-12 billion. LCP Delta

- **Assumptions regarding the ability to re-site generation projects in new areas within the same deployment timescale.** For example, the graphics suggest that the zonal case assumes 13-18 GW of offshore wind might be located off the south coast of England.[9] This is not credible for marine spatial planning reasons and could not be achieved within the timescales of the study. Project re-siting accounts for up to £5.2 billion of the £15.5 billion benefits claimed.
- **Assumptions regarding the location of interconnectors** – which have not been provided – but probably overstate constraint costs and may include interconnectors that have been rejected for revenue support. Interconnector efficiencies account for up to **c.£8 billion** of the £15.5 billion economic benefits claimed.
- **Assumptions regarding market liquidity** and the effect of zonal markets on competition.
- **Assumptions that congestion and producer rents would accrue to the consumer.** This is highly speculative and unlikely and would be subject to several policy decisions and legal challenges from existing rights holders.
- **Legacy costs including the cost of protecting and compensating** existing CfD and network connection rights holders, which would be significant.
- **Wider implementation costs** which would impact the industry, energy supply companies and consumers. For example, the costs of new IT, processes and systems to support a shift back to centralised dispatch.
- **Cost to set-up and operate a multi-billion Financial Transmission Rights (FTR)** trading system.
- **Commercial costs, including the cost to renegotiate thousands of contracts,** PPAs, debt facilities and supply agreements.
- **Ongoing commercial and risk management costs** for market participants, including the cost of participating in the FTR trading, hedging, forecasting and forward trading.

Depending on the chosen design, the ongoing commercial, risk management and transactional costs of operating in a zonal LMP market could be significant.

"The FTR market is inefficient and costly to consumers. The evidence on this is overwhelming..."

Michael Pollitt, 2023 Comments on FTI report for Ofgem.[10]

Based on the LCP Delta/Grant Thornton modelling, Regen believes that the benefits case for zonal pricing is extremely weak and, as the modelling report clearly states, could easily be

[9] LCP Delta has stated that their assumptions around offshore wind are based on *the most generous interpretation of availability provided by the Crown Estate, only based on seabed depth in certain areas"*

[10] Prof Michael Pollitt Cambridge University comments on the FTI Report for Ofgem on the assessment of locational wholesale electricity market design options in GB

reversed to a negative system cost by a relatively small increase in the cost of capital, project delays and by clearly identifiable costs that have not yet been modelled.

The weak business case coupled with the lack of design clarity, industry preference for an incremental reform approach and a concern that the threat of radical market redesign is already affecting investment decisions should provide sufficient evidence for DESNZ to drop the zonal pricing option.

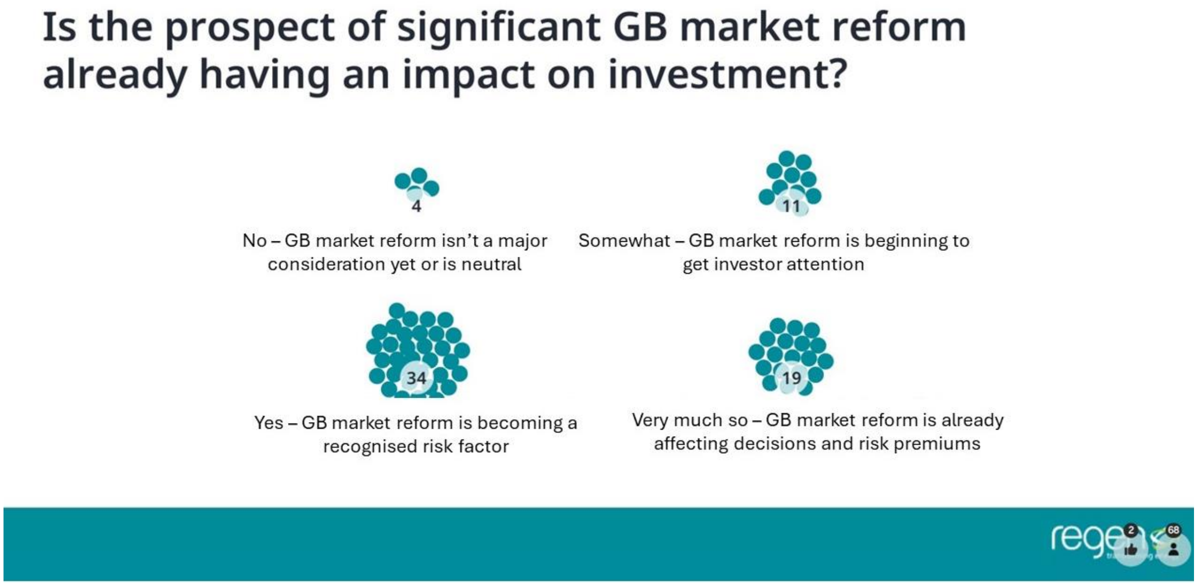

Figure 5: **Participant responses on the prospect of significant GB market reform and its impact on investment**

Source: Regen REMA consultation event 22 April 2024

It is difficult to quantify the investment risk that zonal pricing would bring. A risk comparison with other LMP markets is difficult since investment risk will depend on the state of each market. A relatively stable market, with marginal levels of change, low levels of current and forecasted constraints and a history of building network capacity on time, would have a lower level of risk associated with LMP. The GB market – which is going through a rapid energy transition and a massive net zero investment programme with significant grid infrastructure requirements to overcome current constraints – is not currently in that position.

In Europe both Norway and Italy have a form of zonal pricing. Norway's is historic and reflects its utility structure, focus on hydro power and geography/demographics. Italy has the highest gas dependency for power in Europe and has seen relatively low levels of renewable growth,[11] which may, in part, be due to high zonal price volatility.[12]

The discussion within the REMA engagement forums has focused on a potential increase in the cost of capital. This is a very real risk and could easily exceed one percentage point. However, it is not the only risk as a focus on capital cost assumes that investors can price the future zonal

[11] Institute of Energy Economics and Financial Analysis

[12] Power Engineering International – Volatile Zonal Prices Impacting RE Producers

market. This may be impossible; in which case we could also see a stall in investment and delay in project development.

There are also ongoing risks associated with an LMP-type market arrangement where market participants lose access rights and are reliant on central dispatch. Evidence of this risk is that most LMP markets are supported by a form of financial hedging via an FTR market or other financial contracts. But hedging is expensive, and this additional system cost should be considered as part of the overall cost-benefit analysis. Hedging is also imperfect. It is difficult to secure long-term FTRs and the availability of FTRs may be limited in a high-renewable energy system.

Regen response highlights – zonal pricing

Regen believes that **the case for zonal pricing has not been made**. There remains significant uncertainty around the potential zonal designs and its impact on other reform options, consumers, legacy arrangements and future investments.

The **benefit case is extremely weak and could quickly be reversed** by an increase in the cost of capital, investment delays and other costs that have not been included in the modelling. Combined with industry concerns and investor risks, Regen believes that there is **a strong case for DESNZ to drop zonal pricing as a design option**.

Regen's view is that zonal pricing would almost certainly require a **high degree of centralised dispatch** which would have significant implications for all market participants including storage and flexibility providers.

A programme of progressive reforms **could achieve the benefits identified** for zonal pricing more quickly and with less implementation and investment risk.

If DESNZ decides to retain zonal pricing as an option, more work is needed to firm up the design options and to properly assess its impact. **A more rigorous benefit case** should be developed using realistic assumptions and a progressive counterfactual.

DESNZ should certainly **not move to endorse zonal pricing** as a preferred option until further design work and **a further consultation** has been undertaken.

1.5. Integrated and holistic strategic and spatial planning

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

Since the start of the REMA process, several significant planning initiatives have been put in place that point to a new approach with a more integrated and strategic planning landscape that includes:

- A new national planning framework that includes a Strategic Spatial Energy Plan (SSEP), Central Strategic Network Plan (CSNP) and new future energy pathways.
- New initiatives at a regional and local level to develop Regional Energy Strategic Planners (RESP) and to roll out local area energy plans.

The development of integrated plans that span national and regional boundaries, energy vectors and the alignment of energy assets and infrastructure could provide the locational signals that have been missing in the current market, as well as speeding up planning decisions and adding to investor confidence. They could also support greater devolution and decision making by regional and local government authorities.

In the context of market reform, the development of a more coherent and integrated energy plan is important in that it changes the emphasis and focus of market price signals and locational decisions. It can be argued that strategic planning, coupled with more direct locational signals through leasing, planning, network charges and revenue support would be a far more effective means to convey locational siting signals than market prices.

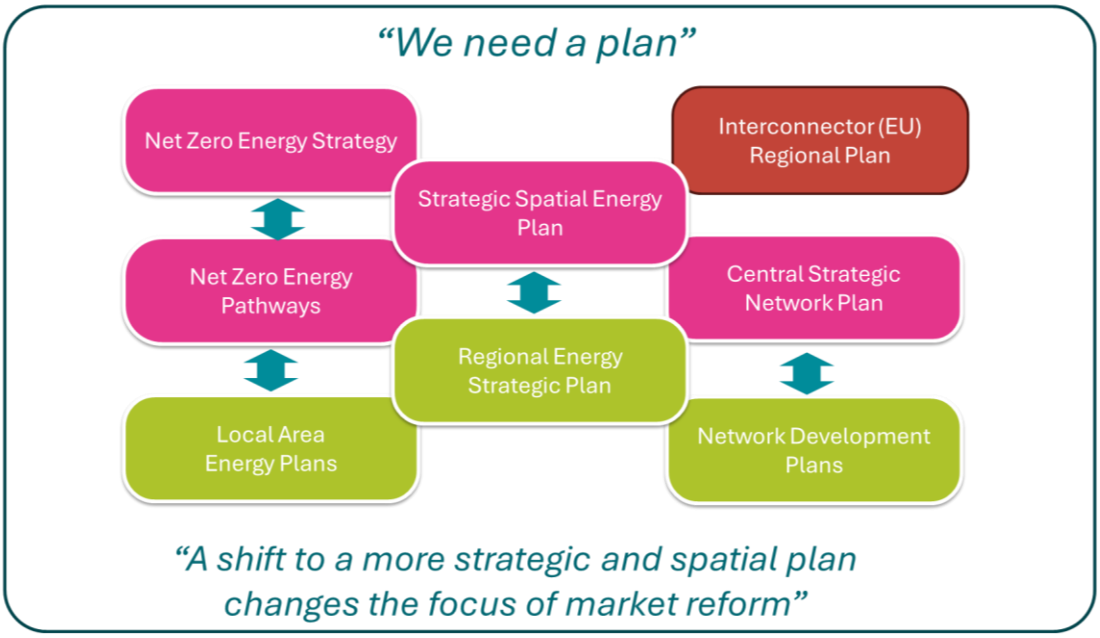

Figure 6: **Regen supports the move to more strategic energy and network planning at a national and regional level to provide greater market certainty.**

The focus of REMA should therefore switch to operational and dispatch efficiency. This would imply, amongst other things, discounting the benefits case and justification for market reforms like zonal pricing that are based on re-siting investment decisions.

Regen response highlights – strategic planning and investment signals

The adoption of a more strategic framework for energy and spatial planning at both national and regional levels should **change the focus of market reform** towards operational and dispatch efficiency.

The combination of strategic planning and more **direct locational signals** through leasing, planning, network charges and targeted revenue support would be a **more effective means to convey locational siting signals** than via wholesale market prices.

DESNZ should **discount asset re-siting benefits ascribed to market reforms like zonal pricing**, these are not credible and can be achieved by other means within an incremental reform package.

1.6. Challenge 1: Passing the value of renewables to consumers

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

The focus on inframarginal rent capture became a hot topic during the energy crisis and is the main reason that the Split Market option was considered;[13] it also led to the imposition of the Electricity Generator Levy windfall tax. Inframarginal rent capture is also part of the producer-to-consumer value transfer which is modelled as a 'consumer benefit' within the LMP benefit case.[14]

Unfortunately, while the Split Market and LMP solutions would, in theory,[15] drive some inframarginal 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. Marginal cost pricing may even potentially be insufficient to cover variable and fixed costs including, for example, debt interest payments.

[13] 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.

[14] 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 liquidity at some locations leading to higher rent taking by some generators is usually not modelled.

[15] 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.

A progressive market reform package would focus on ways to ensure an equitable and sustainable value share between consumer and producer 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.

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 should 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.
- Ensuring that consumers do not pay an unduly high price for capacity adequacy by ensuring that there is sufficient liquidity and competition within the capacity market.

1.6.1. Proposed REMA reforms to ensure consumer value

Regen supports the two main areas of reform that have been proposed to ensure a better value share between consumers and renewable generators:

1) The use of CfDs as a means to set a fair price for renewable energy and to provide consumers with a hedge against future high price periods.

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 price is above their CfD strike price.

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

Looking to the future, analysis by the OBR highlights the benefits to economic growth and society of the transition to net zero from helping to avoid the periodic price shocks that come from the UK's reliance on imported fossil fuels.

Taking account of additional debt interest costs and the impact on economic activity, such recurring gas price spikes would add around 13 per cent of GDP to public debt by 2050-51. This is about twice as much as the 6 per cent of GDP central estimate for the total cost of public investment to complete the transition to net zero by the middle of the century.

OBR Fiscal Risks and Sustainability Report July 2023.[16]

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

- **Maintaining liquidity, price discovery and competition within the CfD mechanism.** 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. Currently this is mainly achieved via competitive auctions. However, a balance needs to be struck 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, a future government will likely need to greatly uplift the allocation budgets for CfD Allocation Rounds (AR) 7-9 to get the deployment of offshore wind back on track to meet future decarbonisation power targets.[17]
- **Extending CfDs contracts to repowering projects** based on investing in new technology and new capacity. This proposal is currently the subject of a separate CfD consultation for AR7 and future rounds.[18]
- **Retaining the option of allowing hybrid CfD or part-capacity CfDs** under which generators can voluntarily 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, thereby potentially encouraging greater liquidity in both intra-day and forward markets.
- **A further option to offer a CfD-type contract to existing generators** in exchange for their remaining Renewable Obligation (RO) subsidies was previously suggested by the government but has not been pursued. We think that this was a missed opportunity, however, its effectiveness now may be reduced with the Electricity Generator Levy (windfall tax) running to 2028.

We agree with the proposal to drop a Cap and Floor approach for renewables. For other technologies Regulated Asset Base and Cap and Floor models also provide a means to deliver a value share with consumers, although their use for higher cost nuclear, dispatchable generation

[16] OBR Fiscal Risks and Sustainability 2023

[17] As a result of the challenges in AR4, lack of offshore wind in AR5 and expected capacity in AR6, GB is far off track to decarbonise power by 2035.

[18] DESNZ, 2024. Proposed amendments to Contracts for Difference for Allocation Round 7 and future rounds.

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.

2) An expansion in the use of long-term Corporate Power Purchase Agreements (CPPAs).

Regen is pleased that the government is exploring the role of Corporate Power Purchase Agreements (CPPAs) as a route to develop renewable generation. Falling under the wider umbrella of Power Purchase Agreements (PPAs), 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 or 'sleever'.

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

In much the same way as CPPAs, as a form of long-term contract which is typically of benefit to both generators and consumers, PPAs not only encourage forward markets by increasing forward market liquidity, but they are key tools to provide the revenue certainty needed to enable developers 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 offtaker.
- 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).

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,[19] 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

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[19] A lack of market transparency and visibility is one of the current market weaknesses that a progressive reform programme must address.

to Spain in Europe with an estimated 14 GW (24%) of renewable capacity under PPA terms.[20] 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, 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 southwest of England and South Wales, a power pool for the steel industry or a power pool that underpins a housing association or a social tariff.

[20] Aurora, 2022. Role of PPAs in the GB Power Market.

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.

Regen response highlights – Challenge 1: Passing through the value of a renewables-based system to consumers

Regen supports the two main REMA proposals to ensure consumer value: 1) The use of CfD to set a fair price and provide a price hedge for consumers; and 2) support for the expansion of CPPAs to enable consumers to buy energy on long-term contracts at lower cost.

The government should look to **develop the wider PPA market**, encompassing the development and use of CPPAs, to allow energy to be bought on long-term contracts at a lower cost.

Public sector bodies, such as local authorities, need to be engaged with more to fully understand and address the challenges of pursuing a PPA for local generation, acknowledging the increasing role of decentralised energy.

Market reform could go further to consider other aspects of consumer value – fuel poverty, local energy supply, fairness and just transition, access to flexibility markets.

The **innovative use of PPAs could provide a basis to establish local and sectoral Green Power Pools** and other local supply arrangements.

As a minimum, DESNZ must ensure that other market reforms, such as zonal pricing, do not adversely impact the development of the PPA market.

1.7. Challenge 2: Accelerating investment in renewable energy

Overall, Regen supports the direction of travel within the 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.

There is, however, a need to have a more whole system and integrated approach to support investment across the entire energy system. It is not possible, or optimal, to focus on investment in renewable generation without the accompanying investment in grid, storage, interconnectors, flexibility and dispatchable generation. 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 net zero investment against 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. This includes both high and very low, or negative, price periods.

There may be some examples of projects that can be financed based solely on merchant risk (short duration batteries being a good example), and some projects may be able to secure a long-term PPA. However, in general, investment in large-scale generation such as wind and nuclear, and long duration storage assets, will require some form of government-backed revenue security.

Revenue security could be in the form of a CfD, Regulated Asset Base investment model, Capacity Market payment or Cap and Floor scheme. There may also be a need arrangements to support fossil fuel generation to act as a backup or reserve capacity.

The progressive market reform package should include the reform and enhancement of revenue support arrangements across the full energy system, so that they:

- Are effective in bringing forward investment at an accelerated pace aligned with an overall net zero delivery plan.
- Ensure value for the consumer in terms of energy supply, security and decarbonisation.
- Minimise any adverse distortion in either investment or electricity markets.
- Provide a means to improve, or not adversely impact, system operational efficiency.

1.7.1. Accelerating investment in CfD allocation round 7 to 9

There is a view that if the next government is intent on accelerating investment in renewables (and offshore wind) it would make as few changes to the CfD scheme as possible and should instead focus on setting an appropriate allocation budget, administrative strike price and budget reference price to boost the rate of renewable deployment. It could even consider switching from an 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 threshold price.

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

1.7.2. 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-AR7' consultation and broader reform options that have been proposed under the REMA programme.

As a general observation and 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. 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. There is therefore a need to bring CfD reforms together into one reform process and to be much clearer about the timing and interdependencies between reform options.

Looking across both the REMA and ongoing CfD reform initiatives, policymakers are tackling several CfD-related challenges:

- 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?
- How do CFDs value **'non-price factors'** including economic development, UK and regional supply chains, environmental value and wider system benefits?
- 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 knock-on **operational inefficiencies**.
- Could CfDs also **inhibit generators from participating in ancillary service markets**, or 'behind the meter' type applications in storage and hydrogen production?
- 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 (forecasted potential) generation**.[21] 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.

Deeming CfD payments warrants deeper analysis as it could meet both criteria of supporting investor confidence and reducing system costs. However, it represents a radical change to the basis of the CfD scheme and requires thorough evaluation against value-for-money criteria. It could also have unintended market effects and implications for non-CfD and legacy CfD holders, necessitating careful consideration.

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 generation curtailment.

The 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. Whilst the voluntary adoption of partial CfDs is viewed positively, enhancing liquidity in forward markets and offering an additional hedge against investment risk,

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

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.

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

1.7.3. Non-price factors – building sustainable supply chains

The progressive reform agenda should 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 AR7 has been welcomed by the industry. SIRs will provide an additional award (alongside regular CfDs) to offshore wind farms that commit to providing enhanced economic value for the UK alongside more sustainable supply chains.

Following responses to a consultation in November 2023,[22] the government has indicated that it will introduce SIR contracts from Allocation Round 7 but based on a 'lighter touch' approach that would include fewer criteria than first proposed:

- Investment in shortening supply chains in deprived areas in the UK.
- Investment in more sustainable means of production anywhere in the world.
- 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 with the suggestion that it may be better to split the SIR scheme into a minimum and enhanced SIR standard and to widen the award of SIRs behind 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.

1.7.4. 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 electrons generated and not whether those electrons have been generated at the right time and place. Combined with competitive auctions, the CfD

[22] DESNZ, 2024. Government Response to the consultation on introducing a CfD Sustainable Industry Reward.

scheme can encourage clustering of assets using the lowest cost of energy technologies and locations. For example, the clustering of wind farms 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.[23] 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 wind farm whose location helped to offset high and low generation in the market.

1.7.5. Supporting collaborative and strategic investment

One of the biggest challenges for the CfD scheme, which has not been addressed by REMA, is how it will support collaborative investment across 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 costs and reduce environmental and societal impacts through collaboration. This in turn creates an interdependency between projects whereby projects co-invest in the grid, marine ports, supply chains, skills, biodiversity gains and other shared infrastructure. All of which the CfD scheme is not designed to support.

Celtic Sea offshore wind is a very good example of this with plans to develop three projects of up to 4.5 GW with an expansion of a further 12 GW. The Celtic Sea projects are a fantastic opportunity for UK Plc and the region.[24] However, this strategic approach will only work if all three projects are delivered in the right timeframe so that co-investment can be made in ports, supply chains and the grid. Competitive CfD auctions may not facilitate this.

[23] Regen, 2022. Go West! An evaluation of the energy system benefits of a more diverse offshore wind portfolio.

[24] Regen, 2022. Floating offshore wind opportunity in the Celtic Sea.

Regen response highlights – Challenge 2: Accelerating investment in renewables

Regen **supports the main direction of REMA to expand the use of a CfD-style mechanism** to support accelerated investment in renewable energy whilst also providing consumers with a hedge against high energy price shocks.

However, there is a need for a **more strategic and holistic approach to investment** that includes investment in supporting infrastructure, supply chains and grid. There is also a need to consider how schemes like the CfD can support **collaborative investment and regional energy strategies**.

We agree with the decision to **rule out CfDs with a strike price range and revenue cap and floor mechanism** for renewable generators.

We agree on the **necessity for more substantial reforms, beyond incremental changes,** to address the challenges of the current CfD mechanism, acknowledging the evolving risk profile under existing arrangements would expose investors to significantly greater risk due to the growing prevalence of negative pricing periods.

The **deeming option should be considered further** and could form the basis of a new CfD approach that would also reduce market distortion. However, this needs careful analysis to understand the impacts on other parts of the market, consumer value, investment in flexibility and other unintended consequences.

Reforms to the reference price structure within an existing 'pay on export' CfD should be developed further.

The purpose and design of Capacity Based CfDs are ambiguous, potentially deviating from the intended concept of CfDs and resembling more closely a capacity payment system.

Whilst some projects may choose to combine hybrid CfD-supported and merchant capacity within the same project, we **do not support the idea of mandatory partial CfDs**.

Overall, the reforms around the CfD have become unwieldy and hard for the industry to follow, with the distinction between short term and longer term CfD reform not functional. We would suggest **bringing all CfD reforms together under one reform programme** and engagement process.

The government should put significant more consideration into support for smaller-scale renewables and local ownership models that have the potential to create wider benefits.

1.8. Challenge 3: Transitioning to a flexible, resilient, decarbonised electricity system

In Regen's 2023 Capacity Market briefing paper we reflected more widely on the purpose and design of the Capacity Market (CM) with a focus on four critical outcomes: [25]

- **Decarbonisation** – ensuring that the CM supports (and does not hinder) the UK's net zero targets.
- **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.
- **Capacity adequacy** – ensuring that the CM and/or other mechanisms are sufficient for an adequate capacity margin over both the short and long-term.
- **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 their position in the Balancing Mechanism (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, incentivise unabated fossil fuel plants to decarbonise or decommission (subject to energy security requirements).

The second REMA consultation focuses on two main areas of reform to support the transition to low-carbon flexibility:

1) Providing support for low-carbon flexibility through the CM

REMA has considered several options to provide greater incentives for low-carbon flexibility in the CM, including:

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

The second REMA consultation report suggests that **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.

From industry feedback Regen has received, the single auction with minima appears to be a pragmatic approach, provided that it is based on an ambitious procurement target for desirable low-carbon characteristics.

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

[25] Regen, 2023. Capacity Market Reform.

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.

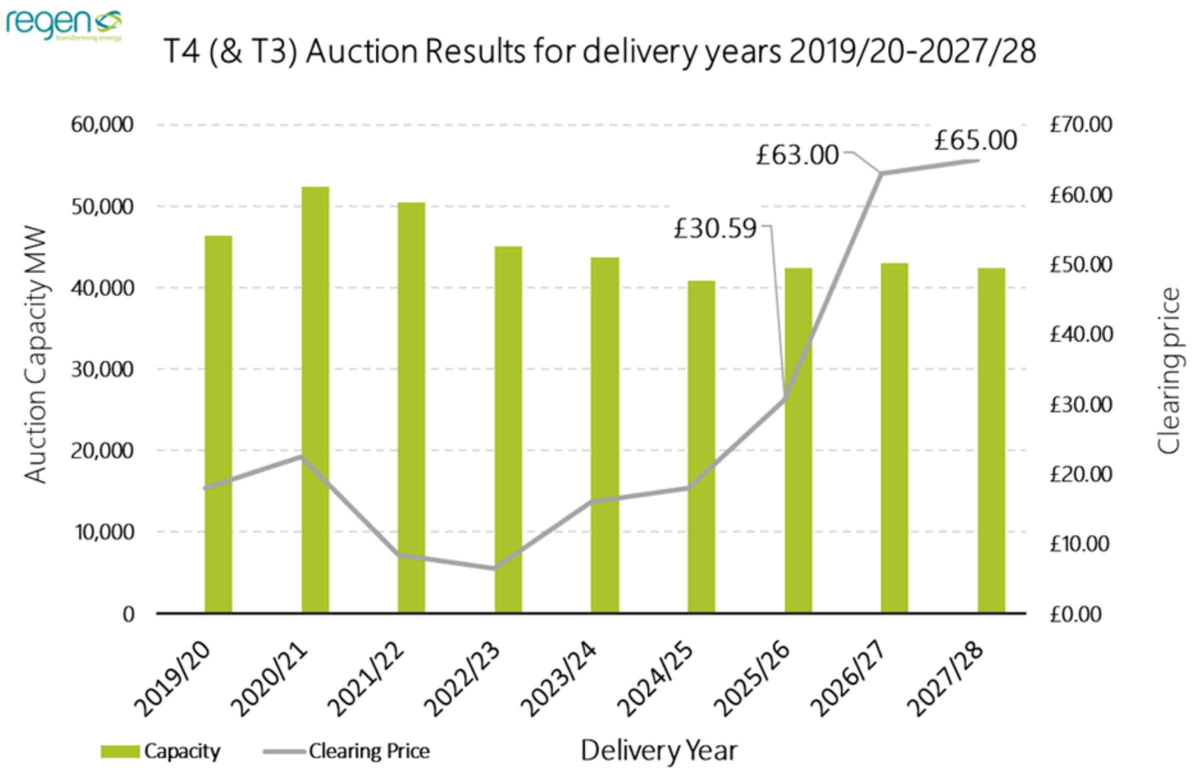


Figure 7: **Capacity market auction results between 2019 - 2028**

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 response to the other CM reforms includes:

- While the review of the storage de-rating factor methodology currently being consulted on by the Electricity System Operator (ESO) is overdue and much needed, the appropriateness and methodology of de-rating factors need to be looked at holistically 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.

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

Encouraging 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 capacity market 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) without a required 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. **Capacity Market '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 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, say, 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 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 back stop, incentive 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 but to smooth the transition to higher carbon prices.[26]

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

[26] DESNZ, 2023. Developing the UK Emissions Trading Scheme: Main Response.

delay their introduction or mitigate their impact. More clarity is needed. from DESNZ on which of these options are being progressed and the timeframe.

Regen response highlights – Challenge 3: Transitioning from fossil fuels to low-carbon flexibility

Regen supports the main direction of REMA to reform the capacity market and introduce a **single auction with multiple clearing prices and minima**, provided it is based on an ambitious procurement target. However more detail is needed on how this design would work in practice.

Regen also supports the other measures that have been proposed **to incentivise the conversion of fossil fuels plants** include emission limits. There is however a general concern that these options are still in discussion without a timetable for implementation.

More focus within REMA should be given to the **cost of the capacity market** and encouraging greater competition (liquidity). There is a risk that the CM clearing price could be set by very expensive marginal generators.

Regen understands why the government has proposed to drop the Strategic Reserve option; however, **a solution is still needed to manage the decommissioning of legacy plant** that may still be needed for energy security. Without a well-considered solution, the likelihood is that a future government will be bounced into a sub-optimal contractual arrangement (as has happened with coal fired plants).

1.9. Challenge 4: Operating a low-carbon system cost-effectively

As already detailed in Section 1.4, Regen believes that the case for a zonal pricing market design has not been made and, given the level of design uncertainty and investment risk such a re-design of the market would entail, DESNZ would be justified in dropping the zonal option.

Regen does not believe that it is possible to move to a decision-in-principle and impact assessment on zonal pricing based on the level of analysis, design and benefit case that has been completed to date.

If DESNZ decides to retain zonal as an option for further evaluation, we would suggest that:

- Greater clarity is needed on the zonal options that are being evaluated and a more robust and thorough benefit case is needed.
- Zonal is deprioritised to become a counterfactual so that more time and resource is available to develop an alternative incremental package of reforms that Regen is calling Progressive Market Reform.

1.9.1. Operational challenges and the case for change

It is clear from the REMA consultation and stakeholder engagement sessions that there is a very strong case that the GB wholesale market, ancillary markets, balancing mechanism and system operation process require both reform and investment in areas such as IT, systems and digitalisation.

The move from 'the Pool' with centralised dispatch to a bilateral trading arrangement following the NETA and BETTA brought significant market efficiencies and price competition. However, while trading arrangements have evolved significantly over the past twenty years, they are imperfect and 'clunky'. Interconnectors are a good example where, since Brexit, market efficiency has been lost.

The basic building blocks of an efficient market are there but at times the market and system operation are misaligned. It also lacks transparency, for participants and the system operator, in key areas such as intra-day bilateral trading and during negative price periods.[27] There is cross-industry consensus that both market and operational systems, data and processes need to be upgraded and further digitalised.

A more dynamic and varied market

In the last decade, the wholesale market has become more dynamic and less predictable, with many more transactions in PPAs, and forward and intra-day trading. This dynamism is partly a response to the growth of more variable, weather-dependent, renewable energy, but it also reflects the fact that there are:

- Many more market participants – including storage and flex providers, paper traders, energy supply companies and aggregators.
- More participants who are connected to the distribution network and therefore may not be visible to the system operator or directly participate in the balancing mechanism.
- Greater levels of interconnection with neighbouring markets.
- A higher level of trading sophistication (and risk-taking) amongst market participants.

There has also been an increase in the number of smaller generators and storage assets that are connected to the distribution network (known as embedded generators) some of whom do not participate in the BM directly but sell their energy through trading 'offtakers' who do participate.

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.

[27] A good example of a loss of transparency occurred during a negative price period on 29th December 2022 when three offshore wind farms that were expected to be offline for six to eight hours began generating after 45 minutes.

Challenges to system operation

As the market has become more efficient and more competitive, it has also become more complex and, at times, challenging to operate. When things go awry – forecasts are wrong, system balances change, network constraints occur – the system operator must work harder and take more actions to bring the system into balance and maintain operability.

This is evidenced by periods with high levels of re-dispatch, 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 action taken by the system operator has a higher price tag.

A further sign of market tension and inefficiency has been the recent appearance of increasing negative day-ahead wholesale prices which have been partly the result of distortions caused by subsidy schemes, as well as a lack of liquidity in short-term markets. Negative pricing may not be a problem in itself and can send strong market signals, but its impact on system operation and the ability of the ESO to predict and respond to changing energy balances needs to be addressed.[28]

These system operation challenges have led to calls for more radical market reform, including LMP, which would also entail a shift back to more centralised dispatch and push some operational risk, such as constraint management, into the wholesale market.

An alternative view is that rather than a step back to centralised dispatch and mandatory trading markets under LMP, the market reform should support both an efficient liberalised wholesale market and efficient system operations. Market transparency is a key reform area. Improved control room functions and enhancement to the BM, alongside new balancing and constraint management services, also feature strongly in the progressive market reform agenda.

1.9.2. Opportunities for progressive market reform

The REMA consultation process, workshops and engagement events have highlighted a very large number of potential incremental reforms that could be implemented within the existing national market arrangements. Taken together this would constitute a very significant and far-reaching package of reforms, which would present its own implementation, governance and coordination challenges, but could be implemented more quickly and with less risk than more radical re-design options.

[28] Operability including frequency control, stability, inertia, constraint management, reactive power, reserve power etc. For a good description see Day in the Life of the Energy System 2035

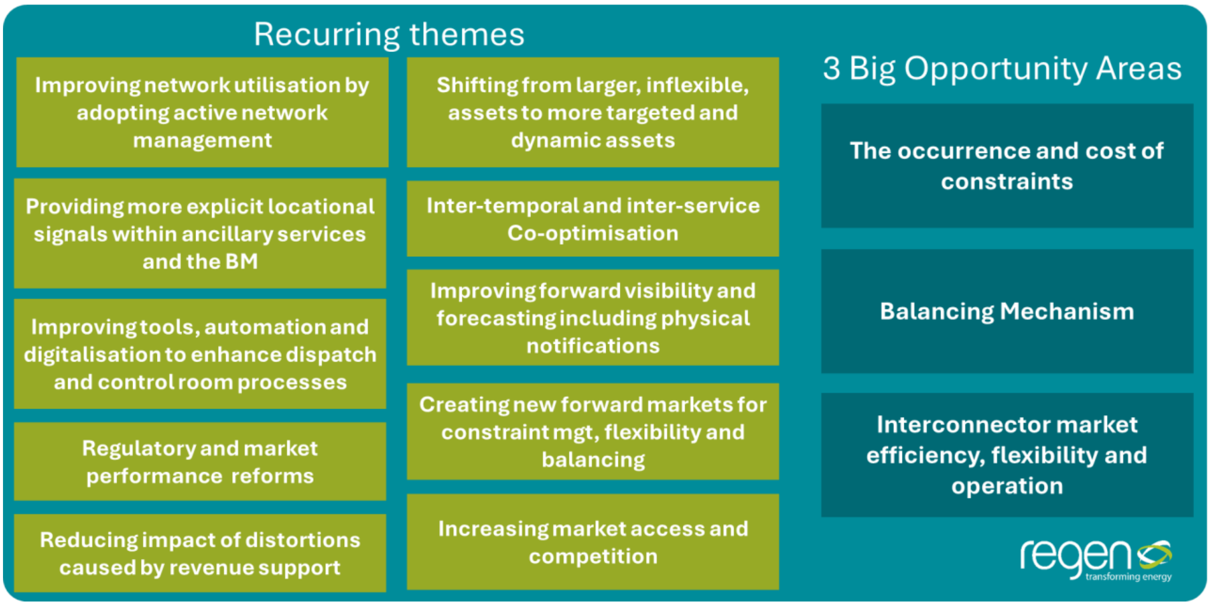
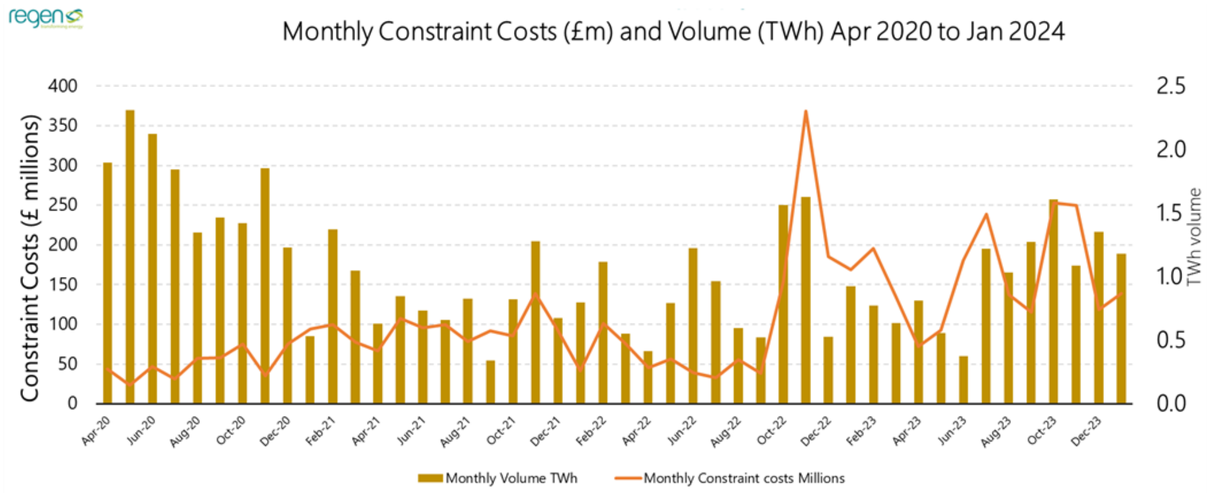


Figure 8: **Recurring themes and opportunity areas for progressive market reform**

1.9.3. Constraint management

The rise in constraint management costs was a key driver to look at radical market reforms such as LMP and red flags raised by the ESO that the current 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 on constraint management costs has been mainly caused by a) a very steep rise in wholesale prices over the energy crisis period and b) the continued reliance on large, and inflexible, gas fired power stations.



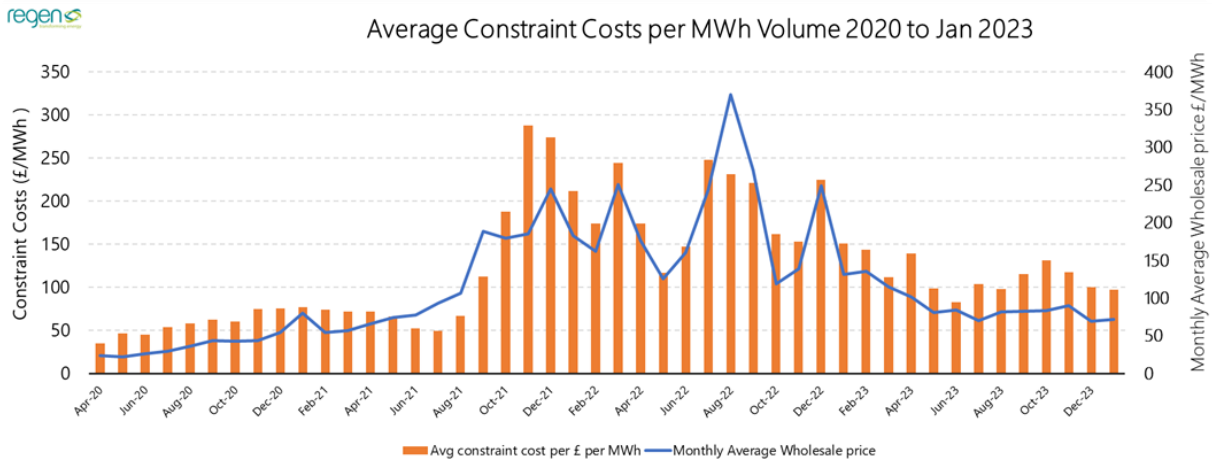


Figure 9: **Rise in constraint management costs, and wholesale prices, Apr 2020 - Jan 2024**

Regen, along with other stakeholders examining constraint costs, has pinpointed numerous reforms, process enhancements, and market advancements capable of diminishing, though not entirely eradicating, both the frequency of constraints and the expense of managing them.[29,30] Many of these ideas and proposals 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.[31]

2. Improvements to forecasting and measures to improve and incentivise more accurate physical notifications.[32]

[29] Examples of Regen studies include Seven Solutions to reduce Constraint Management Costs and evidence given to the ESNZ Select Committee.

[30] See for example analysis by Dr Simon Gill Simon Gill - Exploring options for constraint management in the GB electricity system and by Frontier Economics Reform options for electricity balancing arrangements in Great Britain

[31] The current CMIS reported by the ESO has produced £80m in cost saving in its first 10 months of operation

[32] ESO, 2023. Forecasting Stakeholder Working Group.

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 balancing mechanism so that it creates a market for flexibility providers to bid for what would otherwise be constrained generation.[33]

The current ESO Open Industry Collaboration Project has produced over 30 idea responses.[34] Several of these responses, 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 resorting to turn down generation.

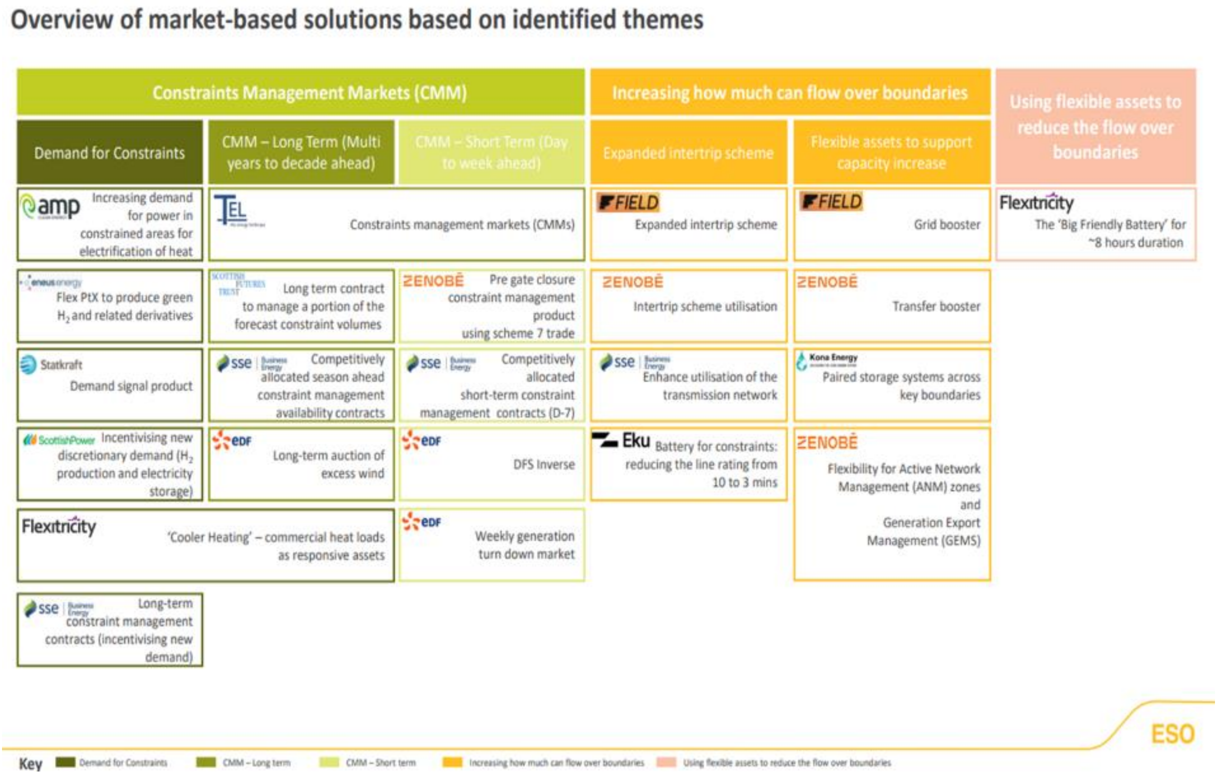


Figure 10: **ESO Open Industry Project on Thermal Constraint Collaboration**

Some degree of constraint is inevitable and even desirable as it would not make economic sense to build a grid so large that they 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 flexibility, are actioned in markets that are truly competitive and in the absence of gaming, manipulation or other forms of market power.

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[33] Similar to the German Government proposed changes to balancing to promote a “Use don’t Curtail” principle

[34] ESO, 2024. Thermal Constraints Collaboration Project.

A key challenge for the system operator right now is that the bulk of constraint management actions are still taken through the balancing mechanism post-gate closure, at a time when control room functions are most under pressure, with inadequate IT and digital capability, predominantly using large and inflexible gas generation.[35]

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 competitive pressure.
2. Enabling the use of smaller, more responsive and flexible, solutions in the BM that can provide constraint management services without creating unnecessary 'bullwhip' effects.[36]
3. Investing in new IT systems, processes and capabilities to enable the control room to utilise a wider range of assets and dispatch multiple assets and to reduce the 'skip rate' whereby more expensive assets are used because of limitations within the control room function.
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 (LCMs).
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 discussed in Section 1.9.4.
7. Allowing interconnectors to provide balancing services, as discussed in Section 1.9.5.

There are some great examples of reforms that are working and help reduce constraint costs. For example, the current Constraint Management Intertrip Service (CMIS) is reported to have saved £80m in its first ten months of operation. The Open Balancing Platform reforms and changes to the limitation of battery dispatch (15-minute rule) have greatly increased the rate of battery utilisation in the BM.

A full study should be made of the potential to reduce constraint costs to reevaluate the projected increase in constraint costs in a national wholesale market with a programme of progressive market reform and to help the National Energy System Operator (NESO) prioritise investment and market development in this area.

1.9.4. Improvements to the Balancing Mechanism

Several of the proposed reforms to the BM have already been highlighted in the previous section on constraint management costs. These include widening the participation in the BM

[35] Studies by LCP Delta, Regen and others suggest that CCGT plants still perform over 80% of balancing turn-up actions.

[36] "Bullwhip" can be described as an overresponse to an imbalance caused by the need to run CCGT plant for longer and at high power output than would be needed.

to many more assets and flexibility providers and the 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,[37] have made a significant impact. Modo Energy has estimated that these changes have coincided with a 100% increase in battery utilisation between Dec 2023 and April 2024.

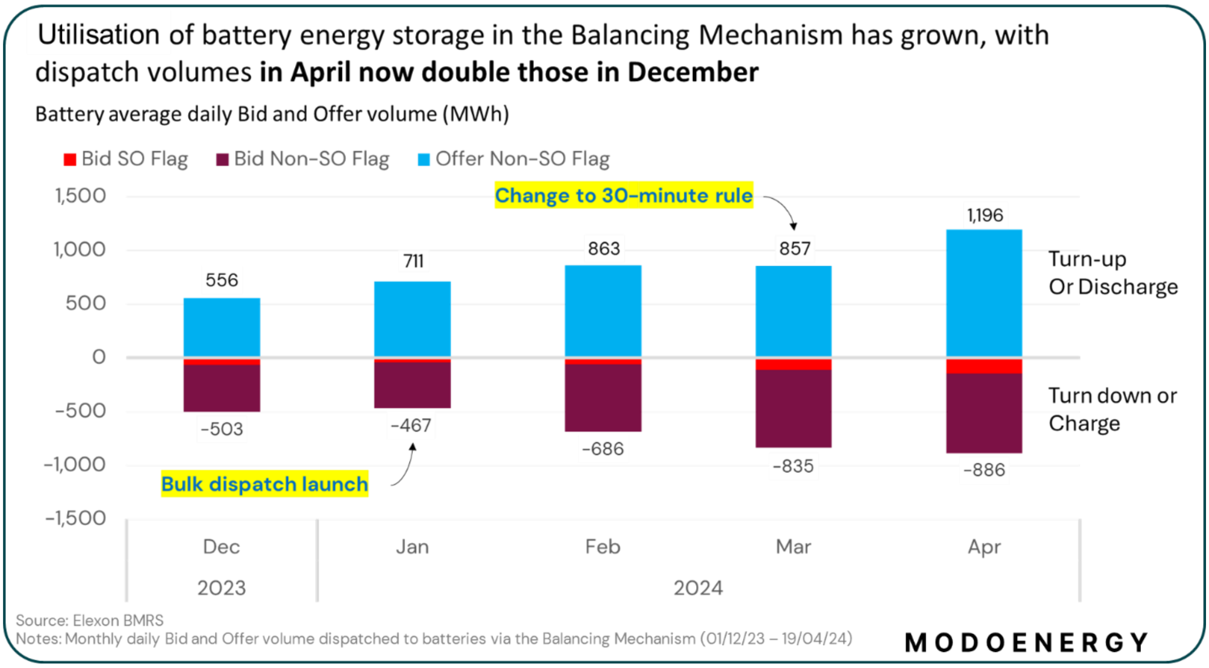

Figure 11: **Changes to battery utilisation in the BM following the implementation of the Open Balancing Platform and changes to the 15-minute rule.**
Source Modo Energy

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 balancing mechanism operated by the 'Control Room of the Future' which would be fully digitalised, highly automated and making use of the latest AI and digital twin technologies such as Virtual Energy Systems.[38,39]

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.[40]

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

[38] ESO, 2024. Virtual Energy System.

[39] ESO, 2024. Balancing programme.

[40] Inter-temporal dispatch optimisation across several settlement periods is currently a process and market challenge

Other balancing reforms that have been highlighted include:

- Measures to increase access, liquidity and 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 capacity market participants within the BM.
- Introduction of more explicit location signals within the BM and other ancillary services to support asset siting.
- Inter-temporal dispatch optimisation across several settlement periods.
- Improved forecast and Physical Notification accuracy.
- Improved asset status visibility; for example, storage, smaller and embedded assets.
- Enabling interconnectors to provide balancing services.

1.9.5. Efficient use of interconnectors

The third big opportunity for progressive operational reform is the efficient use of interconnectors. Interconnectors are expected to 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 – therefore reducing the need for subsidy payments.

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. Therefore, they should be an ideal tool to improve system operation and market efficiency.

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

The complexity with interconnectors however is that the decision to invest in an interconnector and then how it is operated in both trading markets and as a balancing function requires collaboration and co-ordination between at least two system operators and two market jurisdictions, and, in fact, in the context of the EU, interconnector coordination often reaches across multiple energy markets.

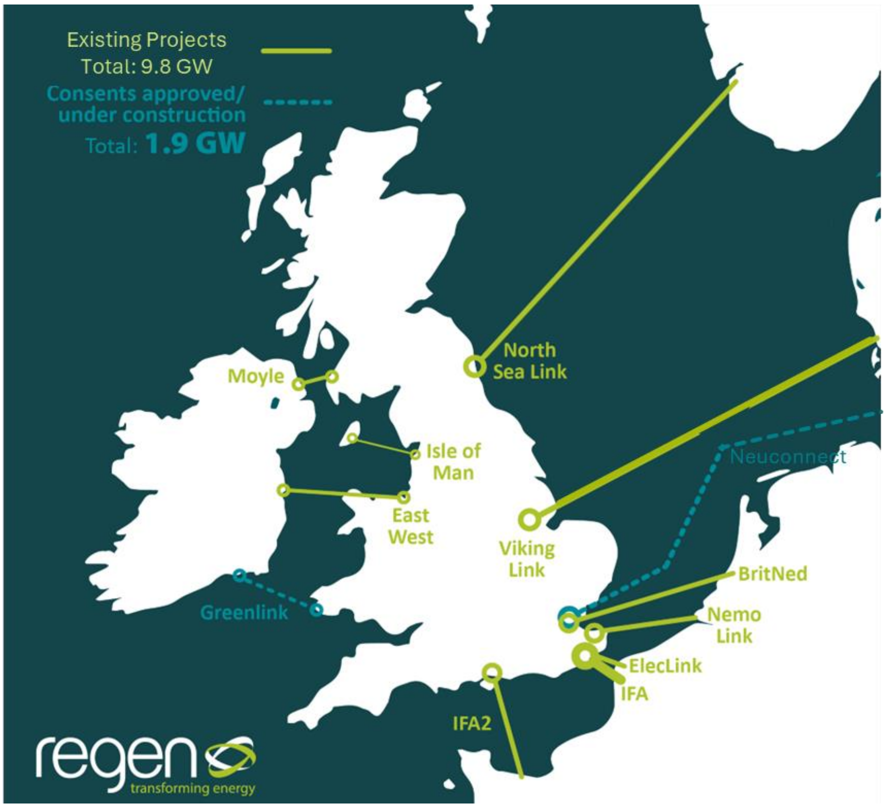

Figure 12: **Current and pipeline GB interconnectors. There are at least another 10 GW in development**

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.
2. Interconnectors may flow into the GB energy system, correctly responding to a national price signal, but **into a part of the grid that is already constrained** thereby adding to 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 for a 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.
- Since Brexit and the Trade and Cooperation Agreement (TCA) **there has been a de-coupling of GB interconnectors from the wider EU energy market.** Although this varies between interconnectors,[41] as a practical consequence this means that trading

[41] 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.

across GB interconnectors is less efficient and can require separate transactions to trade capacity and volume.

- The GB system operator does have some ability to affect interconnector flows (for example through forward counter trading) and does indeed 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.

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.[42] Analyses are currently in progress and will be published shortly.

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

1. **Improving GB strategic planning and cross-border cooperation for interconnectors:**
    - Develop a UK Integrated Circuit (IC) strategic plan aligned within the SSEP and CSNP.
    - Shift from developer led to strategic development.
    - Review the methodology and benefits case analysis used to approve GB interconnector revenue support.
    - Re-engage with EU (ENTSO-E) IC Offshore Network Development Plan and ACERS.
    - Build on bilateral collaboration agreements e.g. GB Island of Ireland energy cooperation MOU.
2. **Improve interconnector market efficiency:**
    - Recouple with EU trading markets.
    - Align GB and IC trading timescales and markets.
    - Re-align GB-ETS /EU-ETS carbon pricing.
    - Establish intraday trading across all ICs.
    - Standardise interconnector trading arrangements and processes.
3. **Manage interconnector flows and enable interconnector balancing:**
    - Greater SO-SO collaboration and coordination.
    - Enhance and enable SO-SO countertrading – energy and capacity – for example looking at how TSO's in Germany and Denmark manage IC flows.
    - Enhance and enable SO-forward market counter trading.
    - Rejoin EU balancing arrangements to allow IC balancing services.
    - Enabling ICs to contribute flexibility potential.

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.

[42] Frontier Economics, 2024. Reform options for electricity balancing arrangements in Great Britain.

1.9.6. Central dispatch

From our engagement with members there is a consensus against central dispatch in the industry with assets retaining the current arrangements of mainly self-dispatch, alongside a set of wider progressive incremental reforms.

1.9.7. Shorter settlement and gate closure

Regen is supportive of a shift to shorter settlement periods. The industry has been asking for reform to settlement periods for years and we were happy to see this type of reform included in the second consultation. A move to a 15 minute period is a reasonable starting point with the aim of a further shift to 5 minute settlement period in the foreseeable future.

Regen was disappointed to see that gate closure shortening has been provisionally discounted in the short to medium term in the REMA process. The impact of shorter settlement periods will be significantly reduced if there isn't any corresponding gate closure reforms and we would like to see this looked at again.

1.9.8. Transmission access rights

Regen is not supportive of a shift to non-firm access arrangements for all existing and new assets. This would undermine business models and investment in GB sector at a crucial time for the deployment of assets on the system.

Regen response highlights – Challenge 4: Operating a high renewables system efficiently

Regen agrees that there are **significant inefficiencies within the current market and system operation**. We do not, however, believe that the current market is fundamentally broken and requires a radical redesign. Nor do we believe that there is an inherent conflict between a dynamic and agile market based on bilateral trading and self-dispatch, and efficient system operation. **The goal of market reform should be to achieve both within a progressive reform programme.**

The UK should set its **ambition to have a world leading electricity market and whole system operation** based on open competitive markets with high levels of digitalisation, automation, smart flexibility and innovation.

There are **lots of opportunities for reform** to current markets, processes and system. The biggest opportunity areas are within constraint management, system balancing and ancillary services and the operation of interconnectors. DESNZ should establish reform programmes, working with the ESO and industry, in each of these areas within the overall REMA progressive reform governance structure.

Progressive market reform will be challenging to deliver and require an integrated programme structure, but almost all these reforms will be needed irrespective of any future market design.

Regen believes that **the case for a zonal pricing market design has not been made** and, given the level of design uncertainty and investment risk such a re-design of the market would entail, DESNZ would be justified in dropping the zonal option.

Regen is **not supportive of a shift to central dispatch** or a shift to non-firm transmission access rights for all new and existing assets that is likely to be needed in a zonal wholesale market with a larger number of zones. Regen is supportive of the shift to shorter settlement periods and would like DESNZ to look again at shortening gate closure.

1.10. Design option compatibility and legacy arrangements

The final part of the REMA consultation, which deals with design option compatibility and legacy arrangements, highlights how much work is still to be done to fully understand the potential impact and cost of market reform. This area will require significant attention in the next phase of the REMA programme.

In part, one of the core challenges the REMA team faces is that many of the design options under the four challenge areas have not been fully defined and, therefore, it is still difficult to be precise about their level of compatibility and legacy impacts.

The biggest areas of concern, and most impactful, is the zonal pricing option. This option should be either dropped or defined in more detail for DESNZ and market stakeholders to form a clear view of how it will impact other design options within REMA and the wider market.

Based on the zonal design option that has been modelled in the Delta/LCP benefit case – which features multi zones, LMP style pricing and a mandatory day ahead market with centralised dispatch – Regen's assessment is that it would have a significant impact on all other design options including the future design of CfDs and the Capacity Market. It would also impact, and could delay, the current work being done by the ESO, Ofgem and industry on network charging, ancillary markets, constraint management, balancing mechanism and interconnectors. We would also highlight that zonal pricing would have a profound impact on retail markets.

Almost no work has been done on the consumer impacts of zonal pricing and its distributional impacts,[43] including the fairness issues that would arise from consumers in one zone subsidising generators to provide low cost energy to consumers in another zone. It is unclear whether consumers would be exposed to zonal price differences.

If zonal pricing is retained as an option, the current second consultation and supporting design documents do not provide a sufficient and robust basis to move to an 'in principle' design decision and final impact assessment. A further design phase and consultation will be needed.

This further consultation should include quantitative compatibility analyses of the proposed policy reforms and a clearer set of proposals to address legacy arrangements.

[43] Ofgem has completed a limited assessment of nodal pricing based on previous modelling.

Section 2: **Consultation question responses**

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

Response to questions 1-3

Q1. What growth potential do you consider the CPPA market to have? Please consider: how this market is impacted by the barriers we have outlined (or other barriers), how it might evolve as the grid decarbonises, and how it could be impacted by other REMA options for reforming the CfD and wholesale markets.

Regen is pleased that the government is exploring the role of Corporate Power Purchase Agreements (CPPAs) as a route to develop renewable generation. Falling under the wider umbrella of Power Purchase Agreements (PPAs), 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 or 'sleever'.

The CPPA market currently occupies a small proportion of the UK's electricity market, supporting around 3.5 GW of renewable capacity,[44] although it is growing. Corporate PPAs are one part of a wider long-term PPA market which has become a significant enabler of renewable generation in the UK – with an estimated 14 GW (24%) of UK renewable capacity is under PPA terms.[45]

Not only have several new renewable projects signed CPPAs for part of their output (for example, Moray West offshore wind farm) but there could be growth post-2027 as some assets transition out of the Renewables Obligation (RO) scheme and opt for longer-term fixed-price contracts, to maintain revenue stability or support potential lifetime expansion or repowering.

The use of long-term CPPAs was overlooked in the first consultation, so it is positive that the government has posed them as a credible market option for exploration as part of REMA and they have been included in this second consultation. Although we believe that CPPAs will remain integral to hybrid financing models for large projects, barriers such as high counterparty risk, high transaction costs and contract length/demand mismatches restrict CPPAs to large, stable offtakers, with good credit ratings and the ability to sign long-term contracts. The complexity of contracting arrangements and the tendency for smaller organisations to lack the

[44] BNEF interactive data set on CPPAs, November 2023

[45] Aurora, 2022. Role of PPAs in the GB Power Market.

resources and financial stability to take on a CPPA currently limits their ability to materially support the development of smaller scale renewables.

In much the same way as CPPAs, as a form of long-term contract which is typically of benefit to both generators and consumers, PPAs not only encourage forward markets by increasing forward market liquidity, but they are key tools to provide the revenue certainty needed to enable developers to raise finance for investment in generation assets. This latter point has been essential for those smaller distributed generators, such as local authorities and community-based projects, where a Contract for Difference (CfD) is not appropriate.

Whilst the consultation concludes that there are no actions for the government to further develop the PPA market, the existing long-term PPA market faces several limitations, including:

- Limited contract and price visibility, impacting system operators and hindering efficient competition and price discovery.
- Complex and challenging to set up, particularly for smaller consumers and generators.
- Long-term contracts require a substantially good credit rating, restricting PPAs to corporations and organisations with strong financial credentials or government support, such as large corporations, prominent industries and major energy suppliers. This is a significant barrier to the growth of the PPA market.

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. The development of the PPA market does not require significant changes to existing market arrangements. Instead, the government should work to encourage the market through regulatory and soft market interventions. For example, offering better guidance and information on PPAs, increasing market visibility and enabling public sector energy procurement.

Regen recommendation:

The government should look to develop the wider PPA market, encompassing the development of CPPAs, to allow energy to be bought on long-term contracts at a lower cost.

Role of PPAs for a decentralised market

As the UK moves towards a decentralised electricity market, REMA needs to recognise the increasing role of decentralised energy and, subsequently, the role that devolved governments, local authorities and community energy groups have in supporting renewable generation in their area, where encouraging the development of the PPA market could be key.

Local authorities will have an especially impactful role in the development of distributed localised electricity. Both as large consumers of electricity and, increasingly, renewable energy developers, local authorities can facilitate the development of PPAs within their area, potentially through underwriting long-term contracts. In addition, many local authorities have set high ambitions for their localities to deliver net zero, including renewable energy targets or technology goals through local area energy plans and other place-based decarbonisation strategies. REMA must support the ambitions of these distributed, locally owned projects, which typically have higher positive impacts to the local area.

A growing PPA market will create further opportunities for these public sector bodies and relevant community energy groups to buy energy from local generators under long-term contracts, facilitating a more decentralised approach to energy supply and demand. However, despite the value and benefits of PPAs to support both new generation and manage price risk in the market, government needs to understand and address the barriers that public bodies and community energy groups face when negotiating PPAs – both as a purchaser and seller of electricity:

- **Diversity and mismatch of PPA lengths and contract types** – this becomes particularly challenging due to the combination of different technologies within the local system.
- **Lack of market intelligence** – local authorities and community energy groups typically do not have the market knowledge and financing to manage the PPA price risk effectively.
- **Limited resources** – local authorities, in particular, experience difficulties taking on and maintaining long-term PPA contracts as resources and competencies are split across a variety of competing sectors.

In addition, many local authorities are already locked into energy contracts through central procurement services. Additional long-term PPA and sleeving arrangements are complex to negotiate and can be difficult to add to existing arrangements.

Developing the PPA market does not require significant changes to existing market arrangements. However, if the PPA market is to become one of the primary mechanisms for the development of distributed generation, there needs to be greater support from the government for local actors to better understand the commercial arrangements behind the PPA market.

Regen recommendation:

The government needs to further engage with public sector bodies, including local authorities, to understand and address the challenges of pursuing a PPA for local energy generation.

Novel approaches and local energy supply

The second REMA consultation has discounted the Green Power Pool option, the argument being that such fundamental reform would not deliver benefits for consumers and would only introduce uncertainty for investors. However, given the current challenges with PPAs for local actors, a similar, localised approach to Green Power Pools could be implemented to bridge the generation gap between a CfD and Smart Export Guarantee.

Regen has been working with several local authorities to assess how novel approaches such as local Green Power Pools, or collaborative sleeving arrangements, could be established to ensure that localities can procure locally generated renewable energy under competitive long-term contracts. Power Pools overcome some of the limitations of PPAs by leveraging economies of scale, facilitating risk sharing and enhancing creditworthiness. They also enable demand flexibility, making them attractive to energy suppliers and constraint management service providers.

A localised Green Power Pool could be viewed as an extension of a shared sleeved PPA and could be set up to allow multiple organisations, including local authorities and other public sector bodies, to participate in buying renewable energy on a long-term contract where they may struggle to procure a PPA directly, due to a lack of sufficient financial backing. An example of this approach includes Bristol City Council's Collaborative Sleeving Pool.[46] Stakeholders in Cornwall are also exploring methods to supply the abundance of floating offshore wind in the Celtic Sea to local businesses, housing associations, communities and fuel-poor customers through a Celtic Sea power pool initiative.

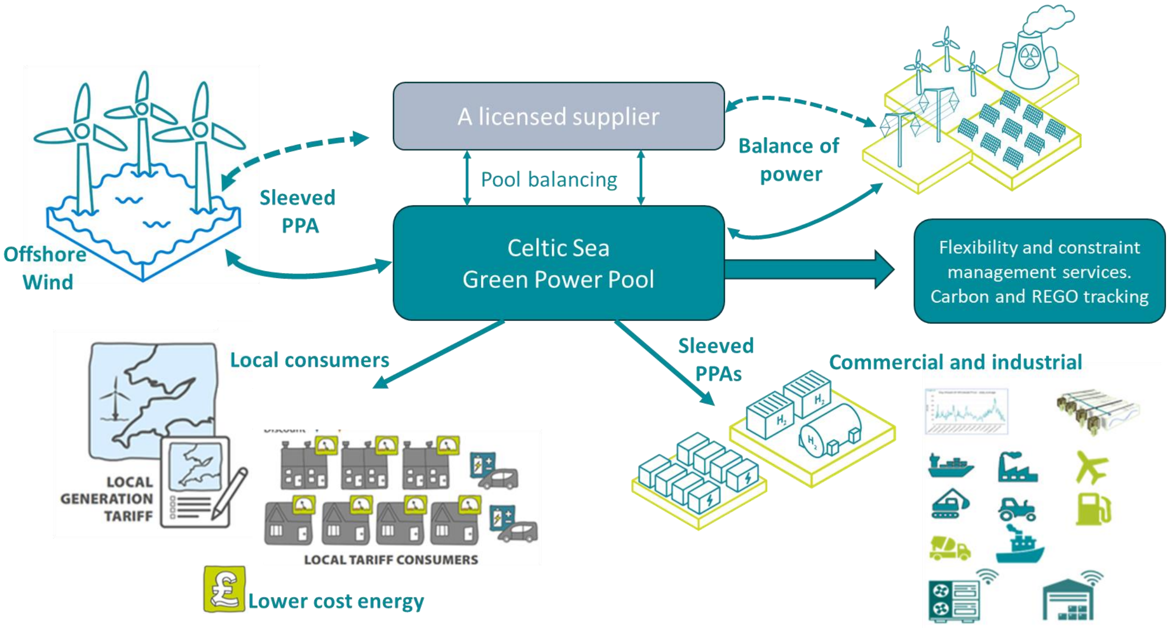

Figure 13: **Illustrative model of an innovative power pool for the Celtic Sea**
Source: Regen

Local energy supply is a key goal for community groups, pivotal in securing community backing for the energy transition and ensuring localities and regions benefit. The use of novel approaches, such as localised Green Power Pools, should offer communities and consumers a way to engage in the energy market, unlocking greater demand flexibility and participation in local constraint markets. This is particularly important as local energy governance and the

[46] Regen, 2021. Bristol City Council – Electricity Sleeving Pool.

provision of local flexibility solutions are set to increasingly important as Ofgem implements plans for Regional Energy Strategic Planners.[47]

Options for local energy supply have not featured strongly in the REMA consultation. However, given the ever-increasing role local and small-scale generators are having in the energy transitions, 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.

Regen recommendation:

The innovative use of PPAs could form the basis of novel approaches, such as localised Green Power Pools, and should be considered by the government and Ofgem as a way to allow communities and consumers to engage in the market. In turn, unlocking greater demand flexibility and participation in local constraint markets.

Future market arrangements and PPAs

Our feedback from industry is that REMA may already be adversely affecting the PPA market. Since its introduction, the REMA process has presented considerable uncertainty regarding future market arrangements, making it more challenging for PPAs to gain momentum as there is no consensus as to future market arrangements. This is exacerbated by the risk that radical changes, such as zonal prices and central dispatch, could be implemented. In particular, a move to zonal pricing would undermine the viability of PPA arrangements as a route to market in highly constrained zones as generators will not be able to make the return on investment due to lower prevailing prices in these zones. Generators would instead have to rely on a CfD to provide a route to market.

An alternative financial contract or the use of Financial Transmission Rights (FTR) would be far less attractive as a vehicle to procure electricity. It would almost certainly be more expensive and complex to transact and would not fulfil the key objectives of procuring energy from a known generator.

The impact around future market uncertainty brought about by REMA has already extended to market dynamics post-2027, where there is reduced liquidity for contracts. This further complicates investment decisions and contractual arrangements and securing contracts beyond this timeline has proven particularly challenging, with both offtakers and generators hesitant to assume volume and price risks.

[47] Ofgem, 2021. Decision on future of local energy institutions and governance.

Regen recommendation:

Government must ensure that other market reforms, such as zonal pricing, do not adversely impact the development of the PPA market. Regen would urge government to make the decision to discount zonal pricing.

Q3. Do you agree with our decision to focus on a cross-cutting approach (including sharper price signals and improving assessment methodologies for valuing power sector benefits) for incentivising electricity demand reduction? Please provide supporting reasoning, including any potential alternative approaches to overcoming the issues we have outlined.

Regen agrees that electricity demand reduction is a key issue that needs to be addressed and managed through a cross-cutting approach. Although markets have a role, the effectiveness of demand reduction intervention in electricity markets relies heavily on factors such as energy efficiency measures, capital costs and network expansion expenses (many of which are features of other markets and therefore are not electricity market-led). As such, permanent demand reduction necessitates a reform of both market incentives and wider policies to deliver demand reduction signals, with a coordinated policy, regulatory and funding framework the most effective approach to deliver permanent demand reduction.

Following extensive engagement with energy efficiency experts, and upon conducting broader research on barriers to consumer and business adoption, the government's planned approach to promoting electricity demand reduction includes:

- **Reviewing government methodology and process for valuing electricity demand reduction** on the basis that the government's policy appraisal methodologies do not value the whole system benefits of electricity demand reduction.
- **Sharpening price signals,** both temporal and locational.
- **Strengthening government spending commitment on energy efficiency,** including improving households' energy efficiencies and supporting a reduction in energy demand for businesses.
- **Deliver the next steps identified in the UK government's Call for Evidence, 'Towards a more innovative energy retail market',** a response to which was published in February 2024.[48]
- **Discount reforms to upstream electricity markets that were specifically designed to incentivise demand reduction** on the basis that additional intervention through upstream electricity markets carries value for money risks and additional demand

[48] DESNZ, 2024. Towards a more innovative energy retail market. Summary of Responses to Call for Evidence.

reduction benefits could instead be secured by building on existing downstream policy interventions.[49]

We agree with the government's planned approach to promoting electricity demand reduction, noting that reforms to the electricity market should not be seen as the primary option for delivering demand reduction signals, and that several policy interventions and funding landscapes are required.

Alongside REMA, Regen has been actively engaging in the government's parallel programme of work on retail market reform and, as such, we are pleased to see that sharpening price signals and progressing the next steps of the Innovation in Energy Retail Markets are included within the government's approach to electricity demand reduction. In particular, the government should look to push forward market-wide-half-hourly settlement and accelerate the rollout of smart meters across the UK. Both initiatives are key enablers of innovation in the retail market and should be aligned REMA initiatives to unlock the value of localised demand-side flexibility – another key enabler of electricity demand reduction.

Whilst acknowledging the significance of permanent demand reduction, within the scope of REMA is it important to note the interaction with demand flexibility. The REMA consultation primarily addresses investment in flexibility assets, balancing mechanism reform and improving temporal signals, such as shortening settlement periods. However, there is limited focus on consumer engagement and encouraging their participation in demand-side flexibility provision.

GB is already seeing more price volatility in the wholesale market. The market is already sending strong time-of-use signals and supporting an increase in agile and flexible tariffs. Incentivising reduced consumption during peak demand has previously ensured capacity adequacy. However, as the UK deploys more renewable energy, there is a growing need to incentivise consumption reduction during periods of low renewable availability (i.e. periods associated with high prices driven by the need to turn on higher-cost backup and standby generation).

Harnessing the demand flexibility of both domestic and commercial consumers, although not permanent demand reduction, is also integral to reducing system costs alongside the frequency of gas-led marginal pricing – both contribute to system reliance and help protect the system and consumers from network stress events. Successful demand side response requires engaging consumers to respond to market price signals appropriately. However, it is crucial to strike a balance between leveraging consumer flexibility and ensuring they are not disadvantaged or unfairly penalised. This entails managing consumer price risk exposure while protecting those unable to respond to price signals. Additionally, fairness in the system is paramount, avoiding arbitrary advantages or disadvantages for particular consumer groups amidst the transition to net zero.

[49] Government considered four policy options for energy demand reduction; 1) continue deployment through government's existing end-use sector policy, 2) introduce demand reduction into the capacity market, 3) create a bespoke par-for-performance scheme, and 4) naturally incentivise demand reduction through other REMA considerations. More can be found in the REMA: Options Assessment.

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

Response to questions 4-13

The consultation opens the discussion of Challenge 2 by articulating the key tension at the heart of the REMA debate: How to de-risk investment in renewables while increasing operational risk exposure to deliver the lowest overall system cost?

There is undoubtedly some tension between instability and operational signals. However, we think the question misrepresents the balance between the two. Whilst there are targeted opportunities to increase operational risk exposure in a way that can lower system costs, those effects will be dwarfed by the impact of ensuring that we develop sufficient investment in renewable capacity and related assets at a reasonable cost of capital.

This impact has not been estimated by any of the major studies carried out so far. Whether the FTI modelling on nodal and zonal pricing for Ofgem, Afry's equivalent modelling for industry,[50] or the recent LCP Delta modelling of zonal versus national pricing for DESNZ,[51] in all cases, studies assume the same generation capacity in GB in both counterfactual and factual cases.

This would not happen. Reforms which increase operational risk and cost for generators would slow investment and make it more expensive. Both outcomes would be poor value for consumers.

For that reason, in response to the question posed at the start of challenge two: ensuring sufficient investment in renewable energy, quickly and cheaply, must be at the heart of delivering on the full range of ambitions for our energy system. It is critical for decarbonising energy and the economy. It is critical for affordability because renewables remain the cheapest form of electricity generation by a factor of two. It is also critical for the security of supply because it is the route to decouple ourselves from international commodity markets, removing the risk of a future price crisis and the potential of being held hostage by geopolitical events.

Over the past decade, the CfD mechanism has evolved from a capped subsidy scheme to a risk hedging mechanism as strike prices agreed for onshore wind, offshore wind and solar have fallen. Although strike prices could rise in AR7 in response to inflationary pressures, these increases will simply follow the general increase in electricity prices that we are seeing post-price-crisis in comparison with expectations a few years ago. Arguably a modest increase in CfD strike prices to support more rapid renewable deployment is a preferred options to mitigate the more extreme societal and economic impact of energy price shocks.[52]

CfDs have delivered direct and clear benefits for both consumers and generators. On the generation side, they have supported investment in 33 GW of capacity. On the consumer side they provided price certainty over 15 years and were the one sector of the wholesale electricity market where, during the price crisis, the net price paid by consumers remained relatively low.

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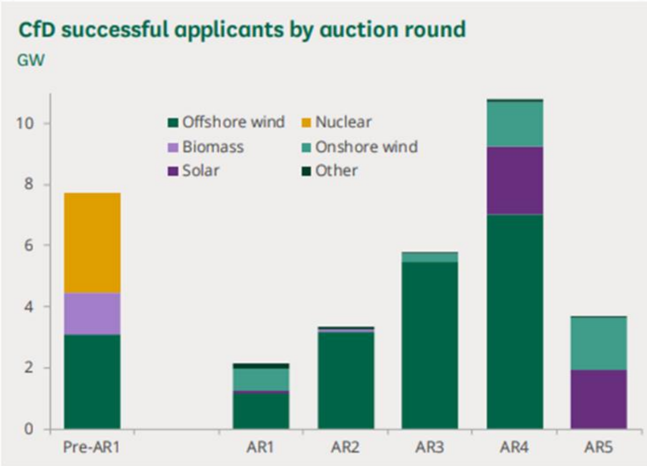
[50] Afry, 2023. Review of electricity market design in Great Britain.

[51] LCP Delta, 2023. System Benefits from Efficient Locational Signals.

[52] The OBR has come to much the same conclusion Source Fiscal Risks and Sustainability 2023.



Capacity of projects awarded CfDs, by technology (MW)

	Auction round						
	Pre-AR1	AR1	AR2	AR3	AR4	AR5	**Total**
Offshore Wind	3,101	1,162	3,196	5,466	6,994	-	**19,919**
Solar PV	-	72	-	-	2,209	1,928	**4,209**
Nuclear	3,277	-	-	-	-	-	**3,277**
Onshore Wind	-	749	-	-	888	1,481	**3,117**
Remote Island Wind	-	-	-	275	598	224	**1,096**
Biomass conversion	1,052	-	-	-	-	-	**1,052**
Dedicated Biomass with CHP	299	-	86	-	-	-	**385**
Advanced Conversion Technology	-	62	64	34	-	-	**160**
Energy from Waste with CHP	-	95	-	-	30	-	**125**
Tidal Stream	-	-	-	-	41	53	**94**
Floating Offshore	-	-	-	-	32	-	**32**
Geothermal	-	-	-	-	-	12	**12**
Total	**7,729**	**2,139**	**3,346**	**5,775**	**10,792**	**3,697**	**33,478**

CHP = Combined heat and power

Figure 14**: CfD contracts awarded to date Source**
Source: Low-carbon Contracts Company

Regen's response to the consultation questions in this challenge can be summarised as focusing on supporting and accelerating investment by limiting risk, recognising the significant hedging benefits to consumers of well-designed CfD-style arrangements, ensuring low costs, recognising wider societal and environmental benefits beyond purely the energy bill, and – rather than focusing on exposing market participants to particular risks – avoiding locking in behaviours that could turn out to be detrimental to the system in future.

Q4. Have we correctly identified the challenges for the future of the CfD? Please consider whether any challenges are particularly crucial to address.

Addressed in Q5.

Q5. Assuming the CfD distortions we have identified are removed, and renewable assets are exposed to the full range of market signals/risks (similar to fully merchant assets), how far would assets alter their behaviour in practice?

There are additional challenges that the CfD scheme should address. Some of these are being taken forward in other reform initiatives but others do not seem to have been identified, for example, how CfDs could not value energy system benefits and how CfD auction processes could create a barrier for strategic co-investment and collaboration.

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-AR7' consultation and broader reform options that have been proposed under the REMA programme.

As a general observation and 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. 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. There is therefore a need to bring CfD reforms together into one reform process and to be much clearer about the timing and interdependencies between reform options.

Looking across both the REMA and ongoing CfD reform initiatives, policymakers are tackling several CfD-related challenges:

- 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 UKs investment targets while securing the optimal cost of energy for consumers?
- How do CFDs value **'non-price factors'** including economic development, UK and regional supply chains, environmental value and wider system benefits?
- 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 **knock-on operational inefficiencies**.
- Could CfDs also **inhibit generators from participating in ancillary service markets**, or 'behind the meter' type applications in storage and hydrogen production?
- 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?

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 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 clustering of assets using the lowest cost of energy technologies and locations. For example, the clustering of wind farms 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.[53] 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 wind farm whose location helped to offset high and low generation in the market.

Supporting collaborative and strategic investment

One of the biggest challenges for the CfD scheme, which has not been addressed by REMA, is how it will support collaborative investment across 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 costs and reduce environmental and societal

[53] Regen, 2022. Go West! An evaluation of the energy system benefits of a more diverse offshore wind portfolio.

impacts through collaboration. This in turn creates an interdependency between projects whereby projects co-invest in the grid, ports, supply chains, skills, biodiversity gains and other shared infrastructure. All of which the CfD scheme is not designed to support and may inhibit.

Celtic Sea offshore wind is a very good example of this with plans to develop three projects of up to 4.5 GW with an expansion of a further 12 GW. The Celtic Sea projects are a fantastic opportunity for UK Plc and the region.[54] However, this strategic approach will only work if all three projects are delivered in the right timeframe so co-investment can be made in ports, supply chains and grid. Competitive CfD auctions may not facilitate this.

Regen recommendation:

Government should bring the full range of CfD reforms into a single coherent programme. Additional challenges that need to be addressed include the recognition of Energy System benefits within the CfD scheme and the way in which CfDs can support strategic co-investment and collaborative investment.

Market distortion challenges

The consultation identifies several market distortion challenges associated with the current CfD design. These can be split into two categories: challenges faced by CfD holders and challenges faced by the system.

1. CfD holder challenges

Revenue uncertainty created by volume risk: high priority

We expect that the growing prevalence of periods of negative pricing will be a significant challenge for CfD holders. This is driven by two factors: reduced revenues and increased risk. Revenue will be lower because generation available during periods of negative pricing will be lost. Given that costs for wind and solar projects are almost entirely based on capacity rather than output, reducing output means that developers will need a higher price on remaining generation and are likely to need to increase their strike price bid in the CfD auction to cover the expected losses.

The exact prevalence of negative prices is also uncertain. In addition to lower expected revenue, that uncertainty equates to further revenue risk. We would expect generators to respond to this by further increasing their strike price bid.

These two elements of the challenge are magnified by the uncertainty in the development of electricity demand and flexibility. As we move into the next stage of decarbonisation, higher levels of demand and greater penetration of flexibility will be needed to keep the prevalence of negative pricing low. High levels of demand will come from successful electrification of heat and transport, and growing levels of flexibility will come from successful development of

[54] Regen, 2022. Floating offshore wind opportunity in the Celtic Sea.

market, regulatory and strategic planning approaches to developing the energy system. These outcomes are beyond the control of CfD holders.

2. System challenges

The system challenges will ultimately be felt by consumers with the costs and risks associated with them passed on either via suppliers or the ESO.

Liquidity: high priority

The impact of CfDs on reducing liquidity has the potential to become a major system challenge. The consultation notes the incentive that current arrangements create to trade energy only in the day ahead and intraday markets. FES scenarios suggest that in a decarbonised system, up to 80% of electrical energy will be generated by variable renewables. If the majority of these are supported through CfD arrangements that could reduce energy available in forward markets to no more than 20% of total. We imagine that forward markets, with such limited liquidity, will be unable to support suppliers and other generators in providing routes to hedge future price risk.

When considering reforms to overcome this challenge, for example when considering reforms to the reference price methodology, it will be important to remember who ultimately holds that risk. For many CfD holders, the renewable project itself effectively sells all its energy forward through the PPA and it is the offtaker which faces the trading risk. Therefore, it is better to characterise the risk as one on offtakers rather than generators. Where offtakers are also suppliers, there may be opportunities to manage this risk through the physical balance of supply and demand within their portfolio.

Dispatch incentives: medium priority

The consultation describes a number of distortions related to dispatch incentives and a lack of incentives to use generation behind the meter or to offer ancillary services.

The distortion is related to the lack of incentives to use generation behind the meter, either through energy storage or behind the meter demand. Whilst this has been perceived as an issue for a number of years, we agree with the consultation that the combination of clarification on existing options for metering arrangements and proposals put forward as part of the CfD AR7 consultation have the potential to ensure that CfD generators are fully incentivise to use generation behind the meter if the expected value of that energy (e.g. the value of hydrogen produced from a behind the meter electrolyser, or the value of electricity at a later time if used to charge a battery) is greater than the reference price at the time of generation.

The second point often discussed in this regard relates to ancillary services. Where these services require a generator to turn down its output. Whilst we agree that there is a lack of incentive, we do not think it is clear how large the challenge is likely to be. In the past few months, the relevant ancillary services markets have tended to saturate due to the increase in battery capacity able to provide them. Whilst the need for these services will rise significantly as renewable penetration increases, there is no reason to think that this would not continue to happen. Even if wind and solar farms were likely to act as ancillary services providers, those ancillary service markets would face the same issue as the wholesale market – they would have an overabundance of supply during periods of high wind or high solar and prices would therefore tend to collapse to zero at the same time as prices were low in the wholesale market.

Regen's view is that investor uncertainty around the prevalence of periods of negative pricing is a major challenge for CfD holders, whilst the biggest system challenge is likely to be overcoming the difficultly in coordinating herding behaviour around artificial cut off points. We also think that forward market liquidity presents a significant issue, but we suspect that there may be a need to think more broadly about the way forward markets operate rather than treating this purely as an issue with CfD design.

Regen recommendation:

DESNZ undertakes analysis to identify the likely scale of renewable contribution to ancillary services provision and to better understand the interactions and dynamics operating between wholesale energy and ancillary services market.

Herding behaviour: high priority

Herding behaviour caused by the introduction of artificial thresholds such as the negative pricing rule present a major challenge for the ESO in terms of operating the system. There are different ways in which this can manifest and we believe this is one of the strongest 'system' arguments for CfD reform:

- It is difficult to identify how bids into day ahead auctions will be influenced by an expectation that the clearing price could be close to zero. For example, there may be an incentive on generators to bid slightly above the marginal price to keep the price above zero. However, as noted above, this incentive will be filtered through the offtaker or portfolio manager that is ultimately trading the power into the day ahead exchange.
- The incentive will depend on the trading arrangements and, where generation is being sold as part of a portfolio there is a risk that trading can create market power opportunities. For example, a portfolio consisting of dispatchable and renewable capacity may be able to act in a way that is likely to influence the probability of the clearing price being above or below zero.
- Although CfD generators (or their offtakers) are incentivised to avoid bidding negative in the day ahead auctions and will therefore should self-curtail if the price in that auction clears lower than zero, there is then the potential for intra-day trading either through exchanges or bilaterally over the counter (OTC) trades, including trades with foreign counterparties over interconnectors which will be difficult to predict for the ESO in the run up to gate closure.

Q6. How far will proposed 'ongoing' CfD reforms go to resolving the three challenges we have outlined (scaling up investment, maximising responsiveness, and distributing risk)?

Ongoing reforms refer primarily to the recent AR7 consultation. Regen responded to that consultation agreeing that the proposals were a positive step forward in the UK's net zero trajectory. We highlighted areas where further thinking is needed about how best to extend the CfD framework to repowered projects, and the importance of working closely with industry to update indexation methodologies for project construction periods in order to continue supporting investment.

The proposals in the AR7 consultation do have the potential to improve the investment environment, manage some elements of risk, and improve responsiveness. In particular:

- Proposals to change the indexing methodology during the construction phase of projects could reduce developer risk associated with inflation on input costs. If designed well, this would support increased investment with potentially lower strike prices. However, as noted in our consultation response, the design of any new indexing methodology needs careful consideration.
- Proposals to integrate repowered projects in the CfD framework can increase investment by ensuring that existing renewable sites near the end of their economic or technical lives can be used to host new equipment often with higher-powered turbines (in the case of wind farms).
- Proposals for new hybrid metering arrangements have the potential to better enable CfD generators to develop behind the meter energy storage and demand and will help ensure they are incentivised to optimise operation of such a co-located system in a way that is more aligned with system needs. That approach will not affect the incentive to provide ancillary services. However, as noted above, DESNZ should further explore the degree to which renewable CfD generators are likely to provide ancillary services in future before using this as a rationale for major reform.

Ongoing reforms can overcome some of the challenges that we face today. However, some of the major challenges will remain. Ongoing reforms cannot solve the issues of increased risk, reduced revenue and increased strike prices driven by the increasing prevalence of negative pricing periods. Nor will they solve the issue of reducing liquidity in forward wholesale energy markets.

Q7. What specific gaming risks, if any, do you see in the deemed generation model, and do any of the deeming methodologies/variations alter those gaming risks? Please provide supporting reasoning.

Regen agrees that a deemed approach to CfDs should be considered further during the next stage of REMA. It has the potential to manage developer risk in a way that could benefit consumers through reduced strike prices. It could also remove distortions and allow projects to respond to signals across energy and ancillary service markets on operational timescales.

However, whilst there is the potential for the model to be effective at managing the challenges of supporting renewables in a fully decarbonised electricity system, the REMA consultation does not provide sufficient detail to enable us to come to a firm view either on the suitability of a deeming methodology overall or on the potential for gaming.

We would expect that, within a well-designed deeming model, it would be possible to mitigate major gaming risks. We think the use of site-specific data, independent third-party oversite, and full transparency of process are likely to remove gaming opportunities.

These principles should be explored in greater detail as more specific deeming models are developed.

Regen recommendation:

DESNZ, working closely with industry, develops a number of more detailed models for a deemed CfD and commissions work to understand how each model could operate.

Q8. Under a capacity-based CfD, what factors do you think will influence auction bidding behaviour? In particular, please consider the extent to which developers will be able to reflect anticipated revenues from other markets in their capacity-based CfD bid.

The consultation proposes a new CfD model based on capacity payments. Under this model developers would be paid a £ / MW / year payment to replace the existing £ / MWh payments. The model would likely include a consumer-protection mechanism which would claw back capacity payments in the event that the wholesale energy price exceeded a certain level. The consultation notes that the capacity CfD has the potential to deliver support to renewables with little or no distortion of market incentives.

Regen's view is that this model is not a true CfD and should not be taken further. A CfD mechanism is, by definition, a risk sharing mechanism where both consumers and developers benefit from reduced future price risk in return for foregoing the potential for either excess returns (for the generator) or excessively low prices (for the consumer).

The capacity CfD proposal is at heat, simply at capacity payment for renewables. Whilst the approach could be adapted in order to overcome some of the issues associated with differing load factors between technologies, fundamentally it does not provide the two-way hedge that is the core benefit of a CfD approach.

The consultation also discusses the use of a gainshare mechanism provides a route to mitigate the risk of windfall gains by the generators, although designing this mechanism will involve setting arbitrary limits on the price at which such a mechanism would kick in and the fraction of gainshare. However, there is no mitigation of the risk of windfall losses to generators. As such, whilst the capacity payment may support investment at a suitably high level, it does not manage the risk of low energy market revenues which has the potential to increase the cost of capital.

Regen recommendation:

DESNZ, working closely with industry, develops a number of more detailed models for a deemed CfD and commissions work to understand how each model could operate.

DESNZ should not take forward the option of capacity-based CfDS.

Q9. Does either the deemed CfD or capacity-based CfD match the risk distribution you detailed in your response to Q25 on which actors are best placed to manage the different risks?

Our answer to Q25 focuses on several high-level principles associated with risk allocation and the need for DESNZ to develop a systematic framework for assessing risk across multiple options.

As stated in Q8, we do not think that capacity-based CfDs represent an appropriate way of sharing risk. This is because it is not fundamentally a risk sharing mechanism, rather it provides a capacity-based lump-sum to developers in return for leaving them exposed to risk. The addition of the gainshare mechanisms which effectively sets a cap on total revenue without any equivalent downside risk mitigation would likely make this an unpalatable option for investors and one that could see the consumer paying excess capacity payments effectively as a risk premium to generators.

By contrast, we think that both deemed CfDs and reforming the traditional pay-on-output CfD models (through changing the reference price) have the potential to deliver an appropriate balance of risk and reward. However, whilst the allocation of risk in these models depends on the detailed design and whilst some deemed models (or reformed market prices) could deliver the right allocation, others may not.

Regen recommendation:

DESNZ and industry work together to define in much more detail how deemed CfDs would operate and develop worked examples of how that could play out in practice. This information would allow a more informed decision to be made on the most appropriate approach to take.

Q10. Do you have a preference for either the deemed CfD or the capacity-based CfD model? Please consider any particular merits or risks of both models.

As noted in our answers to Questions 7 and 8 we do not believe that a capacity-based CfD is suitable and, whilst we think that a deemed CfD has merit, there is not yet sufficient detail available to offer full support.

We agree that a Deeming option for CfDs could reduce investment risk and reduce market distortions and should be further developed, with due consideration of its potential unintended market impacts including for non-deemed generators and flexibility providers.

The design and purpose of capacity-based CfDs are not clear, and such a design would seem to move away from the CfD concept to something that looks much more like a capacity payment.

Q11. Do you see any particular merits or risks with a partial payment CfD?

The consultation lays out an option to limit CfDs to a proportion of the installed capacity of a project. The rationale is that this leaves each project operating some capacity on a merchant basis, and the project overall is partially exposed to market signals.

Several projects have, in recent years, opted to take a partial CfD. The option to do so has allowed innovative hybrid financing models which allow developers to take a more bespoke balance of risk and reward. However, these have tended to be very large offshore wind projects and are supported by PPA agreements with the largest, most credit worthy, corporate entities.

The voluntary adoption of partial CfDs is positive and should be encouraged as it is likely to create more liquidity in PPA and other forward markets and can also provide an additional means to hedge investment risk. However, Regen does not support mandatory partial CfDs. We think it would be very challenging for small and medium-scale renewable projects to gain the long-term contracts needed to manage risk on the merchant portion of the project. Project finance would also likely require very high credit ratings which would potentially reduce the pool of counterparties significantly.

From a system perspective, we are not convinced that partial CfDs would deliver the necessary changes in behaviour. For example, there would be a significant difference between the trading behaviour of a wind farm where output was traded as a single block across both CfD supported and merchant capacity, and one where the output of the two types of capacity were traded separately.

Regen recommendation:

Whilst Regen agrees that the adoption of partial CfDs should be encouraged as a means to increase liquidity in forward markets and hedge investment risk, we do not support mandatory partial CfDs due to the challenges for small and medium scale projects.

Q12. Do you see any particular merits or risks with the reforms to the CfD reference price we have outlined? Please consider how far the two reforms we have outlined might affect both liquidity in forward markets and basis risk for developers.

We agree that reforming the reference price within the current pay-on-output CfD design has the potential to significantly change the way energy from CfD generators is traded. As with other proposals put forward in REMA, we do not think sufficient detail to understand the impact of different proposed reference price methodologies or take a view on their desirability.

Given the potential impact that current arrangements could have on forward market liquidity, we agree that DESNZ should develop this option further. In addition, as part of its exploration of deemed CfD options, DESNZ may want to consider alternative reference price methodologies alongside deeming options.

The current reference price and how it operates in practice

The consultation correctly highlights that the current definition of the reference price is the key factor in removing the incentive to trade energy in forward markets. However, it is also important to characterise how this applies in practice.

Whilst much of the discussion focuses on the risks that generators face, the trading of CfD generation within the market is largely done by offtakers (for independent generators) or portfolio managers (for utility owned projects). Therefore, it is important to remember that it is these actors, rather than the generators themselves, who face the risk and reward incentives on day-to-day trading activities. The generator is usually isolated from many of these concerns behind it's PPA, and the design of the reference price will also impact on the terms of that PPA.

Independent CfD generators will sign a PPA with an offtaker at financial close in order to lock in the market price portion of the strike price. The PPA will usually be for the same duration as the 15-year CfD and terms will tend to require the offtaker to buy the full output of the generator, with price indexed linked to the CfD reference price (currently set by the day ahead power exchange). There will also be a mechanism to ensure the offtaker is rewarded for its services and for managing any risk in the process.

With such as contract, at point of financial close, the generator has removed price risk on all power generated for the duration of the CfD and PPA contracts (with the exception of periods of negative pricing) and has little interest in day-to-day energy trading.

Whilst the context is different for portfolio developers, including those who are vertically integrated, our understanding is that similar 'internal' arrangements such as PPAs between individual generator business units and a 'portfolio manager' are often used.[55]

How will changing the reference price calculation change PPA agreements?

To understand the impact of changing the reference price on trading, it will first be important to consider what impact it could have on the form of PPAs between generators and offtakers.

The needs of CfD generators remain fixed: to reach financial close they need a route to trade power that provides high certainty that they will realise the reference price, however that

[55] From this point we use the term 'offtaker' to cover the activity of any entity that trades the power from a CfD generator. However, it will be important to consider the different context in which this trading is happening and whether this will lead to any difference in outcome.

reference price is defined. Therefore, we think it is likely that PPA terms would continue to offer prices index linked to any new definition of a reference price.

As in the current model, this means risk will tend to be pushed to the offtaker. If a change in reference price increases the level of this risk faced by offtakers, this is likely to increase the risk premium they will charge to the generator for example by taking a larger fee.

How will a change in the reference price alter the trading of energy by the offtaker?

The consultation proposes defining the reference price based on a basket of market prices for a specific settlement period. For example, an average of day ahead, season ahead and year ahead prices. We expect that offtakers would likely use a 'follow the basket' trading strategy where they attempt, as closely as possible, to match the strategy for selling electricity to the definition of the reference price. This would minimise any differences between the price at which they would buy (defined through the PPA and likely index linked to the reference price) and the price at which they would sell.

Offtakers trading power from CfD generators would likely be incentivised to follow the basket and trade power in line with the weightings of that basket.

However, the use of forward as well as day ahead prices will introduce additional complexity and it is unlikely that offtakers will be able to hedge to the same degree as they can under current arrangements. Forward trading means selling energy for particular settlement periods well ahead of forecasts which indicate the likely generation in that settlement period. Therefore, offtakers are likely to need to sell energy in forward markets based on average seasonal load factors and make significant adjustments to their positions in each individual settlement period nearer to delivery.

The next steps in developing options for reforming the reference price will involve exploring in more detail the form of PPAs between generators and offtakers that will evolve alongside, and developing a much better understanding of the likely trading strategies that offtakers will use to optimise their portfolios.

Q13. What role do you think CPPA and PPA markets, and REMA reforms more broadly, will play in helping drive small-scale renewable deployment in the near-, mid- and far-term?

We would like to see a greater role for PPAs in supporting small scale generation. However, we note that investment is currently at a historic low and this reflects the significant barriers associated with any standalone PPA financed project, barriers which can be particularly acute for small projects. We would therefore welcome specific actions to provide better support for small scale renewables and believe that reformed PPA arrangements, backed by government intervention to overcome key barriers, represents a significant opportunity not only for decarbonisation but also for development of local economies.

In Challenge 1, the consultation indicates that DESNZ does not feel there is currently a need for government intervention in the PPA market. Regen does not agree and believes that there are opportunities for the government and Ofgem to provide additional support and backing to encourage the development of the PPA market, especially to support small scale and community-based generation projects.

REMA has so far placed little emphasis on the role of small-scale renewables in the energy transition, and we are pleased to see this question focusing on the needs of these projects. Although small scale projects do not contribute a relatively small quantity of physical capacity, we think their social and local-economic impact is significant. They can play a role in diversifying the ownership mix, integrated into place-based smart local energy schemes, and contribution to local and community energy.

Since the end of the Feed In Tariff Scheme, support for small scale projects has been limited. Today, the only active support mechanism is the Smart Export Guarantee (SEG) which provides a minimum price for electricity exported from eligible projects. However, the SEG is focused primarily on micro generation (<30 kW) projects and the rates offered under SEG remain low.

Whilst the consultation asks about small scale generation in general, we think that the development of small-scale generation should be more closely tied to the development of placed based planning and 'smart local energy systems'. There is a growing focus on local and regional energy planning through the development of Local Area Energy Planning (LAEP), Local Heat and Energy Efficiency Strategies (LHEES) in Scotland, and Regional Energy Strategic Planners (RESP).

We recommend that in the next phase of REMA that DESNZ gives significantly greater attention to local energy and the wider set of benefits that these projects can deliver.

As we discuss in answer to Q1, Regen has supported several projects which have aimed to develop better PPA arrangements for small scale generators, particularly those linked to the concept of local energy.

Three barriers stand out:

- **The complexity of arrangements** – small scale projects do not have the resources of large developers and need support in dealing with the intricacies of the energy market.
- **Insufficient credit rating for offtakers** – small scale projects are well placed to support local energy models and provide power to local authorities, small to medium scale businesses and potentially domestic customers. However, these consumers do not have sufficient credit rating to act as counterparties suitable for securing investment. Regen thinks there is an important role for governments in providing debt guarantees which would enable smaller organisations to act as PPA counterparties. In particular, local government organisations are enduring entities with significant demand and important decision-making powers affecting the local area. As such they are well placed to both support the development of coordinated, strategically planned local energy systems, and to act as long-term PPA counterparties. However, given financing and procurement arrangements for local authorities they would need national government support. The next phase of REMA should explore options for doing so.
- **High costs** – the discussion in Challenge 1 identifies the high transaction costs as a barrier to PPA uptake at all scales. This is particularly true for small projects where many costs do

not scale linearly with project size. Costs such legal fees, IT infrastructure etc. constitute a significantly large portion of overall project costs compared with larger projects. Therefore, intervention to standardise processes, simplify PPA contract formats etc. will have a proportionally greater impact on small scale projects.

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

Responses to questions 14–21

The Capacity Market (CM), introduced in 2013 as a relatively simple subsidy mechanism to ensure sufficient capacity adequacy in the system, has become an increasingly complex market to participate in. We have heard from members that the high administrative burden, additional risks from new penalties, on top of the punitive de-rating factors and the associated methodology, may mean that asset owners simply stop bidding for new CM contracts in the future. This becomes particularly important at a time of capacity scarcity and very high clearing prices, and would clearly not be a good outcome for the industry as a whole.

Furthermore, including the initial REMA consultation, this is the fifth consultation on the topic of CM reform that we have responded to in the last two years. Many proposals have been introduced in those consultations which have not been addressed in REMA and could have important implications for the success of the reforms proposed in this consultation. REMA represents an opportunity to holistically review and reform the functionality of the CM, which has been missed. We urge the DESNZ team to use the REMA reform process as an opportunity to reform the CM governance process to make it simpler and fit for the future and to take a wider, strategic view of CM reform going forward.

On a broader note, CM reform in and of itself is unlikely to bring about the significant levels of flexibility required to realise a decarbonised electricity system without several wider policy interventions, such as strengthened and coordinated price signals and bespoke mechanisms to support developing technologies. Therefore, we encourage the government to continue to take a cross-cutting approach to flexibility, ensuring alignment within policy making and the development of clear and coordinated price signals across various mechanisms.

Q14. Are there any unintended consequences that we should consider regarding the optimal use of minima in the CM and/or the desirable characteristics it should be set to procure?

Whilst our response to the initial REMA consultation stated a preference for the introduction of multipliers into the CM, we are supportive of the minded-to position to take forward a single auction with multiple clearing prices design, with a focus on introducing a minimum procurement target for desirable characteristics. This is due to the supporting documentation suggesting that this is the most effective option for supporting the deployment of low-carbon and flexible technologies in the CM.[56]

However, the second consultation highlights that

"further work is underway to develop how minima should be defined and set (i.e. to procure low-carbon capacity and/or key flexibility capabilities)".

[56] Baringa Partners, Alternative Capacity Market Auction Designs, July 2023.

Without a clear set of definitions and principles around the optimal use of minima within the CM, it is challenging to identify the unintended consequences of such an approach at this stage.

In our insight paper, we highlighted that if the purpose of the CM is to support investment in assets to provide energy security and resilience, then it is important to ensure that the mix of assets that are built provides more than just capacity. This means moving away from a market design that considers all forms of capacity to be equal, and instead values a range of attributes that add to overall system resilience.

The introduction of a minimum procurement target could allow the CM to remain technology-neutral while providing a value weighting towards certain attributes and capabilities that are of value to the energy system. Among various factors, this could encompass diversity and responsiveness, but at the very least, it should prioritise low-carbon technologies.

However, as Figure 16 highlights, the supporting documentation suggests that technologies such as hydrogen and biomass could be defined as low-carbon. If such reforms are delivered without properly defining the conditions under which such technologies can be classified as truly low-carbon (such as the source of hydrogen), this could lead to negative outcomes and deliver outcomes that are inconsistent with the government's 2035 target. Therefore, a clear and accurate definition and supporting methodology of what constitutes as low-carbon is a vital prerequisite to successful CM reform.

Type	Category	Low Carbon	Low Carbon Sustained Response	Low Carbon Response and Reserve
Battery 0.5 - 3hr duration	Battery	Yes	No	Yes
Battery 4 - 6hr duration	Battery	Yes	Yes	Yes
Biogas and Biomass (inc CCS)	Bio	Yes	Yes	No
DSR	DSR	Yes	No	Yes
EfW	Gas	No	No	No
Gas CCGT, OCGT, CHP	Gas	No	No	No
Gas CCS	CCS	Yes	Yes	Yes
Hydro	Hydro	Yes	No	No
Hydro Pumped Storage	Hydro	Yes	Yes	Yes
Interconnector	Interconnector	No	No	No
Nuclear	Nuclear	Yes	Yes	No
Wind	Wind	Yes	No	No
H2 CCGT	Hydrogen	Yes	Yes	Yes
H2 OCGT	Hydrogen	Yes	Yes	Yes
Longer duration batteries	LDS	Yes	Yes	Yes
Longer duration, low efficiency (6hr)	LDS	Yes	Yes	No
Longer duration, low efficiency (12 hr)	LDS	Yes	Yes	No
Established longer duration storage (medium)	LDS	Yes	Yes	No
Established longer duration storage (long)	LDS	Yes	Yes	No

Figure 15**: Provisional definitions for different technology types participating the CM, provided as a starting point for further policy exploration.**

Source: Baringa Partners, Alternative Capacity Market Auction Designs

Members also highlighted the importance of setting long-term targets within the CM that industry can respond to, with a lack of strategic direction currently hampering investment decision making. While the introduction of minima can provide a level of flexibility, with different characteristics prioritised to a different extent each year, a horizon of two-to-five years with clear procurement targets would provide a greater level of certainty to allow for industry to adapt.

Finally, the process of bidding into the CM already involves a high administrative burden, and the introduction of minima with more than one desirable characteristic (low-carbon, sustained response or response time) could materially increase complexity if this process is not properly managed, with the potential unintended consequence of reducing liquidity if participants feel it is no longer sustainable to participate. This is something we discuss in more detail in our response to Q15.

Regen recommendation:

Further details regarding how minima will be defined and set, including a clear definition of low-carbon technologies, should be provided by the government as soon as possible for industry to review. This should include the provision of a greater level of strategic direction, such as initial procurement targets across a two-to-five year timeline, to allow industry to adapt and respond.

Q15. What aspects of the wider CM framework, auction design and parameters should we consider reviewing to ensure there are no barriers to success for introducing minima into the CM?

On a fundamental level, what was introduced in 2013 as a relatively simple subsidy mechanism to ensure sufficient capacity adequacy on the system has become an increasingly complex market to participate in. We have heard from members that the high administrative burden, additional risks from new penalties, on top of the punitive de-rating factors and the associated methodology, may mean that asset owners simply stop bidding for new CM contracts in the future. This becomes particularly important at a time of capacity scarcity and very high clearing prices and would clearly not be a good outcome for the industry.

The potential introduction of minima to the auction risks further increasing the complexity and administrative burden of participation, which might lead to a reduction in assets taking part.

Furthermore, including the initial REMA consultation, this is the fifth consultation on the topic of CM reform that we have responded to in the last two years. Many proposals have been introduced in those consultations which have not been addressed in this one and could have important implications for the success of introducing minima into the CM. REMA represents an opportunity to holistically review and reform the functionality of the CM, which has been missed. There is a risk of focusing too much on the introduction of minima into the auction process to the detriment of implementing other, potentially more impactful reforms, to support the decarbonisation and successful functioning of the CM into the 2030s and beyond.

To this end, the following aspects of the wider CM framework, auction design and parameters should continue to be reviewed as part of the REMA reform process, many of which have been identified in previous consultations.

Regen recommendation:

Ensure CM reform as part of REMA takes a holistic view of the mechanism and recognises the importance of other reforms as highlighted in previous consultations. Publish responses to the government's Phase 2 proposals and ten year review, and Ofgem's Ten-year review of the Capacity Market Rules, and provide guidance as to how next steps following these consultations will complement the REMA process.

Definition of system stress events and the role of de-rating factors

In our response to the initial REMA consultation we highlighted that, while capacity adequacy is important, a focus only on capacity is a reflection of traditional energy security thinking, based on maintaining a certain capacity margin in order to meet a predicted winter peak evening demand. That thinking is in turn based on the logic that, provided there was some capacity headroom against the winter peak, other aspects of energy system resilience could be managed by the System Operator. The definition of a CM system stress event – four-hour duration with sufficient pre-warning for the system operator to issue a CM Notice at least four hours in advance to mobilise large generation capacity – reflects this thinking.

We are pleased to see that the government has recognised this and is exploring the changing nature of future stress events and potential alternative approaches and metrics to the current standard.

Furthermore, any reforms to the reliability standard should also provide a more holistic review of the de-rating methodology, as highlighted in the supporting documentation:

"As de-rating factors are designed to reflect the definition of a system stress event within the current design of the CM, the changing nature of system stress events could raise more fundamental questions for the role of, and determination of, de-rating factors. For example, a de-rating factor which reflects the capability of capacity to respond at times of peak demand will not appropriately reflect capability of the same capacity to respond to sustained periods of low renewables output."[57]

Batteries continue to be one of the highest providers of new build capacity bidding into the CM auctions. However, the de-rating factors for batteries in both the T-1 and T-4 auctions have continued to drop in recent years. We feel that the current de-rating factor methodology, last updated in 2017, is no longer fit for purpose. If the status quo is maintained and the de-rating factors go down further in subsequent auction rounds, battery storage developers will simply not bid in the auction rounds due to lack of revenue versus the costs/penalties/risks.

While the review of the storage de-rating factor methodology currently being consulted on by the ESO overdue, a more holistic review of the appropriateness and methodology of de-rating factors must be undertaken within the context of wider CM reform, to ensure that they are not detrimental to the government's decarbonisation aims. As such, we look forward to seeing the

[57] Baringa Partners, Alternative Capacity Market Auction Designs, July 2023.

output of the government's research project to explore whether Loss of Load Expectation (LOLE) remains an appropriate measure alongside potential alternative metrics, and encourage the government to include a review of de-rating factors as part of this.

Regen recommendation:

The government should undertake a holistic review of the appropriateness and methodology of de-rating factors as part of their programme reviewing the future of system stress events.

Extended Performance Testing

The extended performance test only applies to storage CMUs and has to be undertaken every three years, unfairly penalising and adding costs to these projects looking to enter the CM. While we recognise that the CM should be a technology-neutral mechanism, when comparing the expectations placed upon different technologies, it becomes apparent that the Extending Performance Testing (EPT) process arguably does treat storage CMUs differently from other technologies, going against the technology neutrality principles of the mechanism. This was explained by one member during our workshop:

"On the legal risk and application to other technologies that compete in the in the CM, it's interesting to note [that] the de-rating factor for storage is reduced significantly. The 2023 T-1 de-rating factors for offshore wind and for [a] 1hr duration storage CMU are almost identical – 11.52% and 11.34% respectively. The EPT is also a test of the ability to get close to or very near to the connection capacity, and with a 100 MW 1hr storage CMU versus 100 MW offshore wind, the battery would be required to get to 95 MW for an hour, whereas the offshore wind would only be required to get to 11 MW."

This highlights the disparity between what is expected of storage CMUs in comparison to other technologies – as currently defined, the EPT requires storage providers to reach c.95% of their connection capacity, which is a requirement that other capacity providers do not have. Furthermore, no equivalent mechanism exists for testing the durability of other technologies participating in the CM – in the above analogy, offshore wind would not be expected to prove it could deliver capacity for an extended period of time, nor would it incur penalties for missing said capacity by a MW. Meanwhile, if a storage CMU were to fail an EPT marginally (e.g. by 3%) they could potentially receive an intend to terminate notice.

As such, ESN members have repeatedly raised a concern that the current rules on EPT need reviewing, as reflected in our responses to the January and December 2023 consultations and in subsequent engagement with the DESNZ team. There is a need to address a wider challenge of how to ensure reliable delivery of capacity across all technologies, rather than simply asking the question of how EPT can be optimised for storage CMUs.

For example, one member highlighted that some older gas-fired generators might not be able to reliably deliver for more than 30 minutes but, currently, no mechanism exists to test this technology's durability or penalise the CMU for non-delivery in the same way. Therefore, if the government considers assurance of durability to be a priority, then there should be an exploration of whether EPTs should be introduced for all technologies.

Regen recommendation:

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, reduce the frequency of extended performance tests in the CM for storage CMUs.

Degradation rate in the CM

The current process and systems in place to apply for CM contracts do not take into account the technology characteristics of the current dominant energy storage technology, Li-Ion batteries. This technology has a degradation rate that is well known and understood. Providers limit the number of cycles they do per day to maintain the health of the battery cells and to stay within their warranty guidelines. In the T-4 auction, a 15-year contract is available and a battery storage project will degrade by a certain percentage rate over that time (depending on a variety of operational factors). This means that if they submit any bids using their full capacity they will not be able to meet that requirement over the 15-year contract.

The alternative to this is to submit less than the stated connection capacity at the pre-qualification stage informally, which is not an ideal process and could be improved – we have seen many CMUs bidding with a capacity that is lower than the actual capacity to include the assumed degradation over the length of the contract. This is counterproductive for developers and the bodies involved and limits the potential for this technology to contribute to capacity adequacy to the best of its ability.

It is also a compromise for asset owners who are limiting the commercial potential of their asset, with this reduction of revenue potential often then priced into the business case in the form of higher clearing prices, driving up prices for consumers. In the last five T-4 auctions, the clearing price has consistently increased. While it is difficult to say whether this is a direct result of the treatment of storage CMUs, several of our members have pointed to a potential correlation between the de-rating of storage and rising prices. Furthermore, higher de-rating factors mean more nominal capacity needs to be contracted, which can also drive up marginal price.

However, some members have suggested that if the need for storage CMUs to self-derate was removed, and the true available capacity was recognised, then they might be able to bid into the auction at lower prices for the same asset, due to the ability to provide more capacity to the system with the same asset, reducing the cost to consumer.

While we are aware of concerns around the need for the CM to remain technology-neutral, it should be possible to introduce a mechanism that both recognises degradation curves for storage CMUs and is applicable across all technologies. For example, all technologies could be expected to provide a capacity profile for the contract duration, which could be flat for some technologies and represent a curve for others. There could also be flexibility to allow all technologies to update this and redeclare their capacity regularly – annually, for example.

This would address the fact that storage CMUs are currently being treated differently when it comes to de-rating, accepting the uniqueness of storage CMUs in certain respects and allowing them to compete while still adhering to tech-neutrality.

We raised this in our response to the January consultation, with a recommendation that storage CMUs should have the ability to provide an expected capacity curve for the 15-year contract period that could be re-assessed at intervals (e.g. annually) to update with the actual level of degradation.

We believe that this recommendation should continue to be considered by the DESNZ team, as the ability of the CM to better recognise the degradation of technologies over time would allow for both a) improved visibility of future capacity adequacy, and therefore allow for more accurate auctions to procure additional capacity, and b) better cost reflectivity and, by extension, better value for consumers.

Regen recommendation:

Explore the development of a mechanism that could be applied across all technologies to allow CMUs to provide an expected capacity curve for the 15-year contract period that could be re-assessed at intervals (e.g. annually) to update with the actual level of degradation.

Market coordination and access

The consultation also proposes to align 'longer term' ancillary service contracts associated with CM/CfD contracts. In addition to the need for greater strategic direction to support investment decision-making, we support increased coordination of price signals for the same reason. If the ESO continues to tender for long-term stability service contracts, there is a risk that separate tenders will not attract the most efficient investment in assets that provide both firm power and stability services. Investors may receive conflicting investment signals and revenues from more efficient resources may be cannibalised by more expensive short-term solutions.

Furthermore, as we highlighted in our response to the January long duration energy storage (LDES) consultation,[58] there is a risk that, without further market signals, the intended flexibility from long-duration assets supported via the bespoke mechanism will not be available to the system when required. There is currently no market signal for the operational assets that will be supported by the cap and floor to be dispatching and helping the system in a longer-term stress event that we will likely see in the 2030s. For example, ahead of a shortfall of energy in an extended low wind event, LDES would need to import energy to be full and ready to dispatch over the period. We are supportive of further investigation of a proposed Storage Level Signal

[58] Regen, 2024 Consultation response: Long duration energy storage cap and floor scheme.

(SLS) or similar mechanism, in addition to a cap and floor, to incentivise the operation of assets to meet systems needs that is highlighted in the Carbon Trust report to the government.[59]

As we put in our LDES consultation response, we believe a technology agnostic approach to the LDES cap and floor focused on system needs is more appropriate and we would assume that that any SLS design would emulate that approach. This requires further details of what that signal would look like and how it might interact with CM and other signals.

Overall, this highlights the need for clear, and coordinated, market signals across a variety of mechanisms to support further low-carbon flexibility and LDES development.

Finally, the government's Phase 2 proposals also included the possibility of introducing additional technology classes for DSR – the integration of flexible distributed energy resources into the CM and other electricity markets has significant potential, but there is much coordination and market design work to be done before the benefits can be realised.

Regen recommendation:

The ESO/NESO should continue to strengthen price signals to support and incentivise flexibility, and coordinate these across markets to ensure assets are able to respond in a manner that benefits the system.

DESNZ to investigate a new Storage Level Signal to encourage the right operational behaviour of LDES once deployed.

Co-location

There is more that could be done to encourage the participation of co-located sites in the CM. We define co-location here as when energy storage is sited with generation (normally solar PV) and/or demand, and there is a shared grid connection. This is also known as a hybrid site or a multi-unit site. While we understand there have been some negotiations to allow co-located sites to pre-qualify and win contracts in the CM, the process of engaging the EMR delivery body for each site is inefficient. This needs reform to help improve integration of this type of site in to the CM. There were also discussions in the past regarding the creation of a hybrid CMUs category in the CM open letter from BEIS in 2020.[60] As the number of co-located sites grows at the distribution and transmission network scale, this is something that we would like to see explored in more detail.

Overarching governance

As a more general point, if REMA is formalising the CM as the primary mechanism for ensuring capacity adequacy, then there is a need to simplify the governance and change-management process, which is currently slow and complex. The Capacity Market Advisory Group (CMAG) can provide recommendations which then require coordination between Ofgem and the

[59] DESNZ, 2024 Report on the Role of Ancillary Services to Encourage Low-carbon Operability.
[60] BEIS, 2020. Open letter on new technologies in the Capacity Market.

government to enact. There is an opportunity to reform the governance process to make it simpler and fit for the future.

Regen recommendation:

As part of holistic reforms to the CM, the government and Ofgem should review and seek to simplify the governance of the mechanism.

Q16. Do you agree with the proposal that new lower emission limits for new build and refurbishing CMUs on long-term contracts should be implemented from the 2026 auctions at the earliest?

As we raised in our response to the March 2023 consultation, we are pleased to see that the government recognises that the CM as it is currently designed is inconsistent with net zero, and aims to align the current rules on emissions limits with net zero targets. While we do not support measures which delay CM alignment with net zero, we understand that the 2024 implementation of lower emission limits is not feasible at current timelines. The government should ensure that action is taken immediately to ensure that the rule changes can be implemented in time for prequalification in 2025 to avoid any further delay, which could impact investment in low-carbon flexibility assets. Furthermore, policymaking needs to be clear and consistent, to allow certainty for participants to be able to plan and respond accordingly. When commitments are amended or delayed at short notice, this creates unnecessary uncertainty, which ultimately drives costs up for the end consumer and delays the net zero transition.

In addition to this, further clarity is required on the emissions limits due to be implemented – the proposed changes to emissions limits in the March 2023 consultation did not go far enough in preparing the CM for a net zero future, or in properly valuing the emissions avoided by participation of low-carbon assets in the CM. For example, we raised a concern that continuing to allow fossil fuel generators to meet a yearly emissions limit, even after the intensity emission limit is tightened after 2034, risks creating a situation where unabated gas assets continue to participate in the CM. This is because, even if an unabated asset does not meet the intensity emission limit, it could still generate for a percentage of time annually to meet the yearly limit. By continuing to provide contracts under this principle, the financial incentive of participation might be greater than any penalties incurred for breaching the yearly emission limit, incentivising them to maximise their output to maximise revenues regardless of any emissions limit.

Regen recommendation:

Provide clarity as soon as possible on emissions limits proposals and the implementation pathway of this in the CM.

Q17. If you are considering investment in flexible capacity, to what extent would emissions limits for new build and refurbishing capacity impact your investment decisions?

Our members are supportive of the introduction of emissions limits. However, there are also, more fundamental investment challenges for battery storage that need to be addressed, as highlighted in our response to Q15.

Q18. Considering the policies listed above, which are already in place or in development, what do you foresee as the main remaining challenges in converting existing unabated gas plants to low-carbon alternatives?

As the consultation states, several policy mechanisms currently in development intend to support the shift to low-carbon dispatchable power, such as the Dispatchable Power Agreement (DPA) to incentivise CCUS. However, while the building blocks are being developed to allow unabated gas plants to convert, challenges do remain.

Our members have raised that, for those looking to decarbonise their existing unabated assets, while H2P and CCUS do offer promising solutions, they are still far off the needed level of commercialisation to support near-term conversion. Furthermore, while recent policy developments are starting to provide some clarity, far more certainty is required before CM participants can make firm investment decisions based on a reliable, cost-effective and sufficient hydrogen supply.

The government's priority should therefore be the continued development of clear, coordinated policy to support the commercialisation of emerging technologies, including more strategic direction regarding how different technologies such as H2P, LDES and CCUS will be working to support a net zero system. An overall strategy needs to be communicated to the industry to provide confidence in the approach and, as such, we suggest that the government develops an updated flexibility and storage strategy, including an update to the 2021 Smart Systems and Flexibility Plan.

Regen recommendation:

The government should continue to prioritise the development of clear, coordinated policy to support the commercialisation of CCUS and H2P, as well as providing a clear overall strategy for the role and scope of low-carbon dispatchable power in the future energy system.

Furthermore, while support mechanisms for transitioning to low-carbon technologies are vital, the CM continues to send a strong signal in support of investment in new unabated gas generation, to the detriment of commercially well-established low-carbon technologies such as battery storage. The government states

"We also expect that carbon pricing through the Emissions Trading Scheme (ETS) and Carbon Price Support (CPS) will play a role in incentivising and increasing the competitiveness of alternatives to unabated gas."

However, it is notable that 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. We welcome the proposal from the government to reduce the UK ETS Cap to bring carbon prices in line with net zero targets and smooth the transition to higher carbon prices over time and highlight the importance of properly functioning carbon pricing in supporting the transition.[61]

As a part of this, Regen and the ESN have been raising the issue of accounting for carbon in operational signals for several years (e.g., see our position paper published in 2020).[62] It is an area we have engaged closely with National Grid ESO on through the ESN's Markets and Revenues Working Group. It is imperative to have better valuation of carbon across all electricity markets, including clear carbon reporting on all markets and services. We welcome the data being provided by the ESO from the BM and the new methodology for carbon reporting of DSO services. However, we would welcome further ESO actions to monitor the carbon intensity of the services and markets they deliver. We have been working with the ESO on how the new NESO could work more effectively in driving net zero delivery. Better monitoring and reporting of the carbon intensity of different markets, such as the CM, would highlight the extent to which the current structure renders it incompatible with decarbonisation targets, strengthening the case for reform.

Regen recommendation:

Give NESO the mandate to monitor carbon intensity and prioritise low-carbon assets in market services, such as the CM. Continue to strengthen the UK ETS to provide a stronger decarbonisation signal.

Finally, we are concerned by the intention to incentivise additional investment in unabated gas when low-carbon flexible technologies can be built by the early 2030's, and the potential unintended consequences of this. Competition from unabated gas plants with CM contracts, even for limited running hours, could negatively impact investment in low-carbon alternatives. Policies to encourage new build unabated gas could have the perverse effect of chilling investment in the very low-carbon flexible technologies that the government is seeking to encourage and could lead to stranded assets – in contradiction of the REMA assessment criteria of delivering value for money for consumers.

[61] DESNZ, 2023. Developing the UK Emissions Trading Scheme: Main Response.

[62] Regen, 2020. Building flexibility markets for a net zero electricity system.

Q19. Do you think there is currently a viable investment landscape for unabated gas generation to later convert to low-carbon alternatives? If not, please set out what further measures would be needed.

In addition to the measures set out in response to Q18, we would suggest that the government continues to consider how it will manage end-of-life fossil assets that should not participate in the market but may need to be retained as standby and backup generation.

While we recognise the government's motivations for removing a Strategic Reserve option, and fully support the drive to ensure that fossil plant is either converted to low-carbon or shut down, there will inevitably need to be a process in place to ensure that the decommissioning of legacy plants does not put energy security at risk.

As we explored in our CM insight paper,[63] 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 consumers. Politically, leaving legacy fossil plants within the CM and main wholesale markets may also make it harder to press forward with decarbonisation across other forms of generation.

The current strategic reserve 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 plant.

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 traditional Strategic Reserve or another approach needs to be considered, including, in extremis, a form of state ownership.

A well designed solution could enable the SO 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 bounced into a poorly designed strategic reserve 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.

[63] Regen, 2023. Capacity Market Reform.

2.4. Q20. Do you agree that an Optimised CM and the work set out in Appendix 3 will sufficiently incentivise the deployment and utilisation of distributed low-carbon flexibility? If not, please set out what further measures would be needed.

The work set out in Appendix 3 was a helpful summary of many of the key challenges that has been identified by our members, and many of the mechanisms listed to improve operationality for distributed low-carbon flexibility should continue to be explored, such as addressing skip rates in the BM, improving standardisation for revenue stacking and lowering the participation threshold to include smaller providers in the market.

However, as identified in our response to Q15, there is much coordination and market design work to be done before the benefits of DSR and distributed flexibility can be realised and, as discussed in our response to Q3, within REMA there has been limited focus on consumer engagement and encouraging their participation in demand-side flexibility provision. We were therefore pleased to see the focus on market-wide half-hourly settlement in the government's response to the 'Towards a more innovative energy retail market' Call for Evidence,[64] and highlight the importance of this in unlocking distributed flexibility. We urge the government to continue to enact retail and wholesale market reforms in tandem, to maintain alignment across energy market frameworks and to ensure that consumers can benefit from a decarbonised electricity system in a just and fair manner.

In addition, our members have raised that the ongoing issues around grid connections represent a significant barrier.

Regen recommendation:

Continue to explore retail and wholesale market reforms in tandem to ensure that consumers can benefit from a decarbonised electricity system in a just and fair manner.

Q21. Do you agree that our combined proposed package of reforms (bespoke mechanisms for certain low-carbon flexible technologies, sharper operational signals, and an Optimised Capacity Market) is sufficient to incentivise flexibility in the long-term? Please set out any other necessary measures.

Please see response to Q15, exploring additional reforms that are required as part of the CM.

More broadly, as discussed in our response to Q14, without a clear set of definitions and principles around the optimum use of minima within the CM, it is challenging to identify unintended consequences of such an approach at this stage.

As the reform process continues, it is important that the government continues to take a holistic approach and ensure that measures set out in the REMA consultation align with existing policy

[64] DESNZ, 2024. Towards a more innovative energy retail market: Summary of Responses to Call for Evidence.

and policy being developed outside of this consultation. CM reform in and of itself is unlikely to bring about the significant levels of flexibility required to realise a decarbonised electricity system, without strengthened and coordinated price signals, as well as bespoke mechanisms to support developing technologies. We therefore agree with the approach to progress with the design of bespoke market arrangements for certain low-carbon flexible technologies on a separate timeline to REMA process.

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

Responses to questions 22-24

There are lots of opportunities for reform to current markets, processes and system. The biggest opportunity areas are within constraint management, system balancing and ancillary services and the operation of interconnectors. DESNZ should establish reform programmes, working with the ESO and industry, in each of these areas within the overall REMA progressive reform governance structure.

In most key areas we are supportive of the overall REMA direction of travel and the options that have been proposed. However, we believe that the benefit case for zonal pricing has not been made and that the design options for zonal pricing have not been clearly defined. Our engagement with industry suggests that this view is shared by the majority of REMA stakeholders. Given the weak benefits case, and the implementation and investment risk during a period of energy transition, we recommend that DESNZ drops the zonal pricing option to reduce investor uncertainty and focus resources on other reform solutions.

Regen is not supportive of a shift to central dispatch or a shift to non-firm transmission access rights for all new and existing assets that is likely to be needed in a zonal wholesale market with a larger number of zones.

Should DESNZ decide to keep zonal pricing as an option, we advise undergoing an additional design phase and consultation before any decision-making. This entails conducting a comprehensive evaluation of design options, cost-benefit analysis, and assessing compatibility and legacy impacts associated with zonal pricing.

Regen's view is that the benefits of an efficient energy market, and REMA's four challenge objectives, can be better and more quickly achieved through a programme of progressive market reform, based on the foundation of the current national trading market arrangements. Progressive market reform will be challenging to deliver and require an integrated programme structure but almost all these reforms will be needed irrespective of any future market design.

Regen is supportive of the shift to shorter settlement periods and would like DESNZ to look again at shortening gate closure.

Q22. Do you agree with the key design choices we have identified in the consultation and in Appendix 4 for zonal pricing? Please detail any missing design considerations.

The design and options for zonal pricing are extremely unclear. Although options have been identified at a high level, they have not been defined in the consultation.

As DESNZ acknowledges, zonal pricing could come in a variety of options, some of which would retain many features of the current market whilst others would require an extreme market redesign. Regen's primary concern that the zonal pricing model is still unclear has been reflected in feedback received from our members and industry colleagues. Our REMA event survey showed that only two out of 73 delegates polled felt that the zonal design option was clear from the information provided, the majority thought it was unclear (Figure 17).

"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 Review of Electricity Market Arrangements Options Assessment 2024

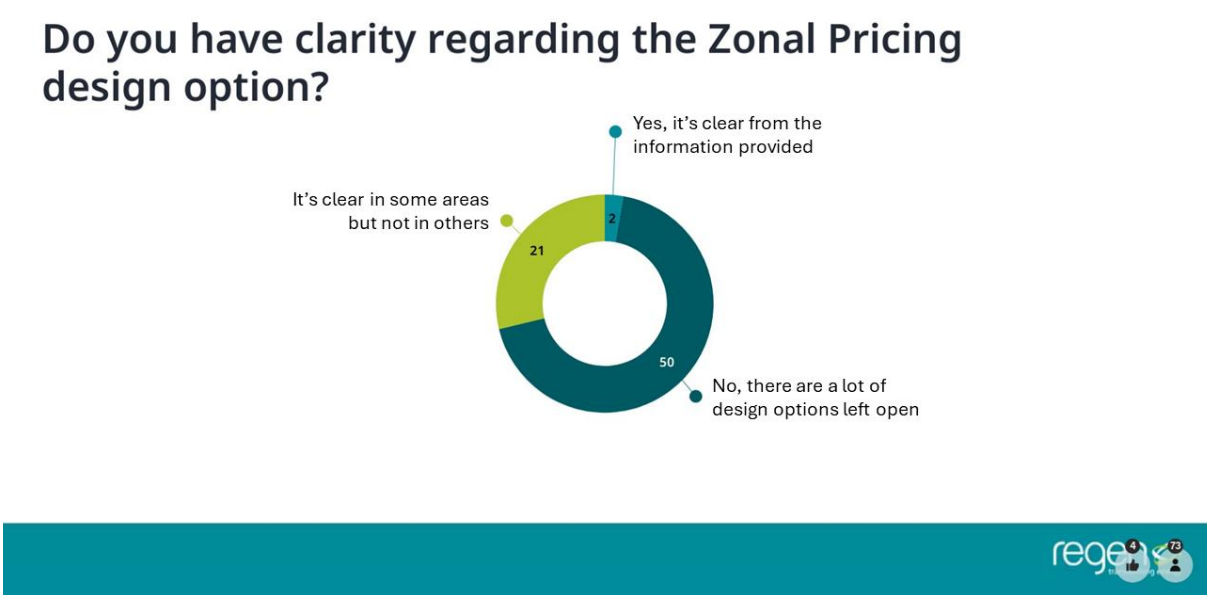


Figure 16: **Participant responses on zonal pricing design option clarity.**
Source: Regen REMA consultation event 22 April 2024

The current discussion and zonal market design is overwhelmingly focused on helping to resolve transmission constraints and transmission connected assets. There has been limited discussion on the impacts of a zonal market on embedded/distribution connected assets, which are a large proportion of the existing renewable energy and electricity storage projects on the system.

Regen understands that more work is being conducted by the REMA team to develop the zonal pricing option. However, it is currently extremely difficult to assess the impact of zonal pricing, or even judge how such a market design would be implemented within the context of the current GB market and net zero transition.

Every aspect of the zonal design requires more detail, but especially:

- The definition of zones and how zones might change over time.
- Dispatch arrangements and whether zonal would include a shift to centralised dispatch (which would almost certainly be the case).
- Demand exposure to zonal price signals and how this would be implemented in retail markets.

- The distributional impacts of zonal pricing and its fairness between zones and between consumer groups within zones.
- Arrangements for forward trading, Financial Transmission Rights (FTR), markets and hedging.
- Zonal impacts on CfD design including reference price, negative price rules and alignment with CfD REMA design options including deeming.
- Zonal impacts on network charging and the ongoing reforms to both the Transmission Network Use of System (TNUoS) and Distrbuted Use of System (DUoS) charges.
- Zonal impacts on current ancillary markets, including for frequency response, reserve services, flexibility and constraint management.
- All aspects of how zonal pricing would impact distribution network connected assets and consumers.
- Interaction and integration with EU markets and interconnection.

Transmission-focused assessments and bias

The current discussion and zonal market design is overwhelmingly focused on helping to resolve transmission constraints and transmission-connected assets. There has been limited discussion on the impacts of a zonal market on embedded/distribution-connected assets, which are a large proportion of the existing renewable energy and electricity storage projects on the system.

Regen recommendation:

DESNZ to provide a wider assessment of the impacts of shifting to a zonal market in further analysis and publications, including embedded/distributed connected assets.

Central versus self-dispatch

Although it is not clear in the consultation our expectation is that any form of zonal pricing with multiple zones will almost certainly require a greater degree of central dispatch, and once that Rubicon is crossed it seems likely that zonal pricing would require a step back to a mandated pool market and centralised dispatch.

This is a significant issue for the industry and especially for storage and flexibility providers whose investment model has been based on the sophisticated optimisation of their asset utilisation to access multiple revenue streams. Asset owners experience to date with the BM dispatch process and the high level of 'skip rates' raises significant doubts about the commercial merit of relying on a central dispatch process controlled by a system operator.

Regen would advocate retaining the current arrangements of mainly self-dispatch, alongside a set of wider reforms in the settlement period and the Balancing Mechanism. We do not believe centralised dispatch is good option for the GB market and that a good degree of the current concerns can be solved from progressive incremental reforms.

Regen recommendation:

If the zonal option is proposed DESNZ must provide clarity on dispatch arrangements and what safeguards will be provided to ensure that asset owners are not disadvantaged by a shift back to a mandated pool market and central dispatch.

Demand side exposure and consumer impacts

Our impression is that very little design work has so far been conducted to look at the demand side exposure of zonal pricing, or the extent to which demand customers would be directly exposed to zonal price signals. It appears that very little work been done on the consumer impacts of zonal pricing and its distributional impacts,[65] including the fairness issues that would arise from consumers in one zone subsidising generators to provide low-cost energy to consumers in another zone. It is unclear whether consumers would be exposed to zonal price differences.

This is an extremely complex and critical area that has a high degree of overlap with retail market reform and the role of energy supply/retail.

Regen's view is that, in principle, consumers should be exposed to wholesale market price signals where these relate to the overall supply/demand balance of the GB energy market. However, we do not believe that all consumers should be exposed to price signals in the wholesale market that are ultimately driven by system requirements such as system constraints, flexibility, ancillary services, frequency or balancing. These signals should instead be targeted to consumers and asset owners that can respond via flexibility and ancillary service markets.

Intra-zonal mechanisms

A further point that has not been part of the design options discussion so far is the impact of the zonal design on transmission and distribution system within the zone, intra-zonal. What access rights do assets have intra-zonal? How are transmission and distribution constraints managed within zones? Depending on where zones are located, there could be unintended consequences and additional challenges created on the electricity network. This intra-zonal impact assessment should be included in any further detailed work on the zonal market design.

[65] Ofgem has completed a limited assessment of nodal pricing based on previous modelling.

Regen recommendation:

DESNZ should accelerate ongoing work to determine the degree to which demand should be exposed to zonal price signals including an analysis of distributional impacts and questions around the fairness of using the wholesale price to give constraint management signals.

DESNZ to include further analysis of intra-zonal impacts of a zonal wholesale market design.

Grandfathering and legacy arrangements

A zonal market is assumed to have market/grid access that is non-firm, meaning a market participant only has a right to access the market and dispatch when instructed to do so by the market operator. In theory, no constraint payments are made to the generator. In practice, existing transmission rights holders are likely to be compensated in some way as they have built their project on an assumption of firm access to the transmission network. A new market for Financial Transmission Rights (FTRs) is proposed but is highly uncertain. As well as network access rights the existing revenue support mechanisms (e.g. CfDs) would have to be grandfathered.

The report on the System Benefits from Efficient Locational Signals published alongside the consultation from LCP Delta and Grant Thornton states that, 'an assessment of grandfathering costs is out of scope of this study'. Grandfathering costs are likely to be significant cost and we believe that this should be clearly communicated and understood ahead of any further consultation on a zonal market. We recommend that an assessment on grandfathering costs be done, if it has not been done so already, to accurately reflect the costs of shifting to a zonal market model.

Regen recommendation:

DESNZ to complete and share further analysis on the grandfathering costs of shifting to a zonal wholesale market.

Cost of capital and Investment Risk

We are pleased to see more focus on the impacts of LMP on the cost of capital coming through in the second REMA consultation and in the accompanying reports. LCP Delta analysis suggests that only a relatively small increase in the cost of capital by 0.3-0.9 percentage points could reverse the benefits that have been modelled and instead deliver a negative system cost of £2-12bn.

“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 March 2024 (report for REMA team on zonal LMP)

This is a critical factor in any radical market reform decision, and we are already hearing from members that there is a risk premium driven by the current uncertainty in the reform options for the GB market. Audience feedback at our REMA engagement session on 22 April confirmed that there has already been impacts on investor confidence (see Figure 5).

This message aligns with other industry surveys and some of the feedback in the first REMA consultation response summaries. The challenge we now have is that the macroeconomic environment has shifted significantly since the REMA reform process started and we have entered a period of higher interest rates which has changed the availability of capital. This means that project finance has become more challenging to raise and that the investment community has looked to other investments and jurisdictions for reasonable returns, where the policy uncertainty is less pronounced.

Cost of capital is important but is not the only risk as a focus on capital cost assumes that investors can price the future zonal market. This may be impossible; in which case we could also see a stall in investment and delay in project development.

There are also ongoing risks associated with an LMP-type market arrangement where market participants lose access rights and are reliant on central dispatch. Evidence of this risk is that most LMP markets are supported by a form of financial hedging via an FTR market or other financial contracts. But hedging is expensive, and this additional system cost should be considered as part of the overall cost-benefit analysis. Hedging is also imperfect. It is difficult to secure long-term FTRs and the availability of FTRs may be limited in a high-renewable energy system.

Regen recommendation:

DESNZ should fully assess the implications of any policy changes on the cost of capital, taking into account the more challenging macroeconomic environment, and make sure this is a high priority in any further work or final options assessment.

DESNZ must also consider other risk factors including the that investors are unable to price future zonal prices resulting in project delay and the ongoing commercial and hedging risk associated with operating in a more volatile market with LMP.

Alternative forward trading and Financial Transmission Rights arrangements

If zonal pricing is adopted it is expected that this would be accompanied by a new mandatory day ahead trading pool and centralised dispatch. This could therefore completely change the way in which the market currently conducts forward bilateral trading and PPA contracts. Instead, these would be expected to become purely financial transactions.

Our feedback from industry is that REMA and the risk of zonal pricing may already be adversely affecting the PPA market. In particular, a move to zonal pricing would undermine the viability of PPA arrangements as a route to market in highly constrained zones as generators will not be able to make the return on investment due to lower prevailing prices in these zones. Generators would instead have to rely on a CfD to provide a route to market.

An alternative financial contract or the use of Financial Transmission Rights (FTR) would be far less attractive as a vehicle to procure electricity. It would almost certainly be more expensive and complex to transact and would not fulfil the key objectives of procuring energy from a known generator.

The impact around future market uncertainty brought about by REMA has already extended to market dynamics post-2027, where there is reduced liquidity for contracts. This further complicates investment decisions and contractual arrangements and securing contracts beyond this timeline has proven particularly challenging, with both offtakers and generators hesitant to assume volume and price risks.

Such arrangements are likely to be costly to establish and will reduce the value of the benefits that have been claimed.

"The FTR market is inefficient and costly to consumers. The evidence on this is overwhelming..."

Michael Pollitt, 2023 Comments on FTI report for Ofgem.[66]

[66] Prof Michael Pollitt Cambridge University comments on the FTI Report for Ofgem on the assessment of locational wholesale electricity market design options in GB

Regen recommendation:

DESNZ should set out its proposals, outline design and costs to establish alternative forward trading arrangements including plans for the use of any FTR type mechanism. The costs and value transfer impact of these arrangements need to be included in the zonal pricing benefit case.

Next steps – more details please

Therefore, if DESNZ is minded to retain zonal pricing as an option, a more detailed design needs to be presented to market stakeholders and a further consultation undertaken. There is insufficient detail and clarity of design to move to a decision-in-principle to adopt zonal or proceed with an impact assessment, as suggested for the REMA programme's next phase.

Industry stakeholders have echoed Regen's preference for a more detailed design of zonal options before any decision is taken to proceed with zonal pricing (Figure 18).

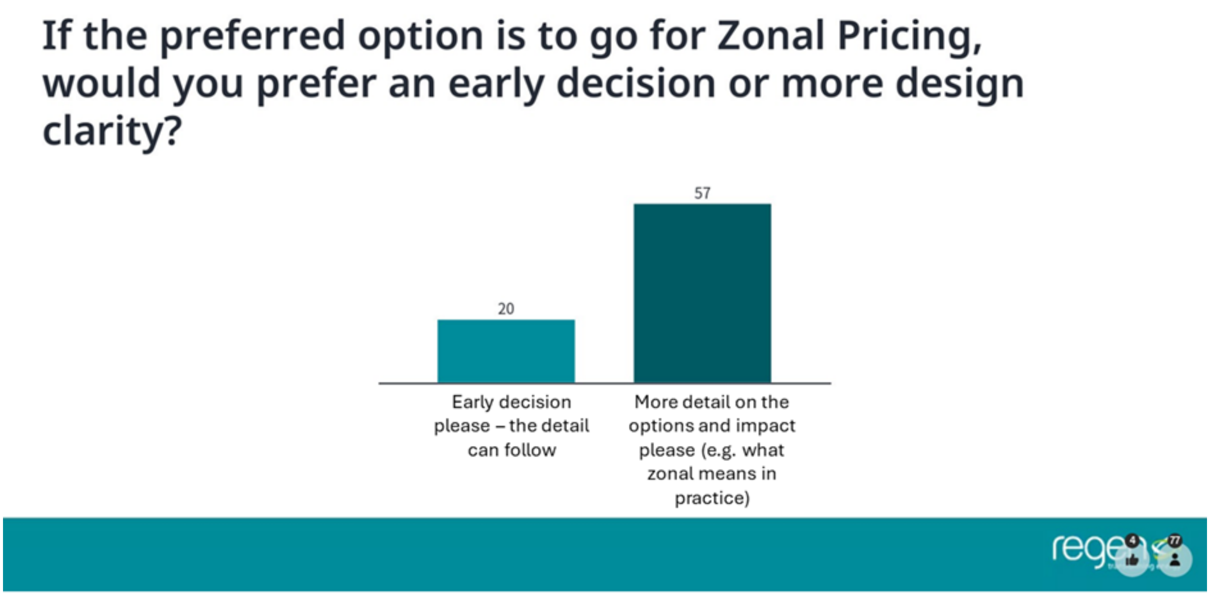


Figure 17: **Participant responses on the next steps for decision-making on LMP.**
Source: Regen REMA consultation event 22 April 2024

Regen recommendation:

DESNZ to provide industry more details on the proposed design of a zonal market in GB to make an informed decision. We would like to see an additional consultation with further details shared with industry, ahead of any final options being produced in mid-2025.

Q23. How far would our retained alternatives to locational pricing options go towards resolving the challenges we have identified, compared with locational pricing? Please provide supporting evidence and consider how these alternative options could work together, and/or alongside other options for improving temporal signals and balancing and ancillary services.

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

Since the start of the REMA process, several significant planning initiatives have been put in place that point to a new approach with a more integrated and strategic planning landscape that includes:

- A new national planning framework that includes a Strategic Spatial Energy Plan (SSEP), Central Strategic Network Plan (CSNP) and new future energy pathways.
- New initiatives at a regional and local level to develop Regional Energy Strategic Planners (RESP) and to roll out local area energy plans.

The development of integrated plans that span national and regional boundaries, energy vectors and the alignment of energy assets and infrastructure could provide the locational signals that have been missing in the current market, as well as speeding up planning decisions and adding to investor confidence. They could also support greater devolution and decision making by regional and local government authorities.

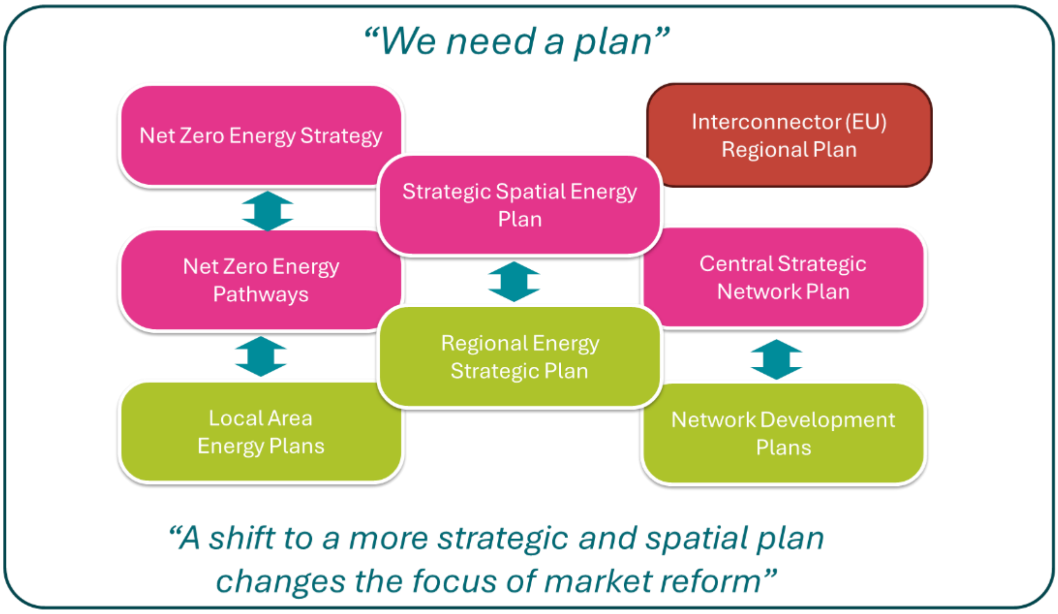


Figure 18: **Regen supports the move to more strategic energy and network planning at a national and regional level to provide greater market certainty.**

In the context of market reform, the development of a more coherent and integrated energy plan is important in that it changes the emphasis and focus of market price signals and locational decisions. It can be argued that strategic planning, coupled with more direct locational signals through leasing, planning, network charges and revenue support would be a far more effective means to convey locational siting signals than market prices.

The focus of REMA should therefore switch to operational and dispatch efficiency. This would imply, amongst other things, discounting the benefits case and justification for market reforms like zonal pricing that are based on re-siting investment decisions.

Alternative Locational signals

Regen 2023 paper sets out a number of alternative sources of locational signal that we believe, combined with strategic planning, can send a far more direct and effective locational signal to inform investment and asset siting.[67] It seems obvious to us, and many in the industry, that more direct forward-looking locational signals would be more effective than a theoretical and extremely hard to forecast location zonal price. This is especially true for renewable and other generation projects such as nuclear that will take a decade or more to develop.

Our conclusion is that reform is certainly needed, but that there are several opportunities to deliver more effective locational signals within a relatively short delivery timeframe by implementing reforms that are largely within the existing market arrangements:

- Reforming network charging to give a transparent and dependable forward cost signal.
- Continuing reforms to network connection and queue management processes towards anticipatory investment and increasing alignment across locations.
- Providing a more explicit location signal in the Balancing Mechanism (BM) and other ancillary services.
- Identifying future flex requirements and continuing to develop operability, flexibility and local constraint management markets/services to enable the utilisation of a wider range of assets.
- Improving planning locational signals, aligned with infrastructure investment, at a national and local level, including strengthening the power of integrated net zero delivery plans, Regional Energy Strategic Plans (RESPs) and Local Area Energy Plans (LAEPs).

One of the easiest ways for networks to provide locational signals to investors is to produce forward looking heat maps showing areas of expected constraint and areas where they are likely to require flexibility and constraint management services. As is being done successfully by Distribution Network Operators.

TNUoS Transmission Network Charging

TNUoS already provides an extremely strong forward price signal for generators connecting to the transmission network. The cost difference between Scotland and the South of England is significant and has recently risen again in the most recent ESO forward forecast.

[67] Regen, 2023. Improving locational signals in the GB electricity markets.

In fact, it could be argued that TNUoS is sending too strong a signal that is currently a barrier for onshore wind projects in Scotland resulting in a lower deployment rate, an absence of merchant projects and higher CfD prices.

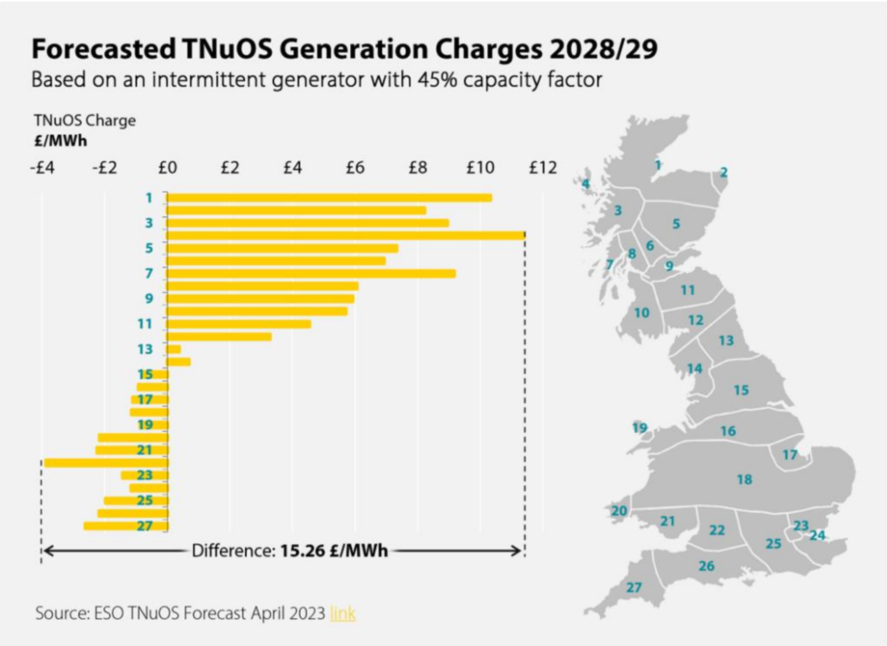


Figure 19: **Forecasted TNUoS Generation Charges 2028/29 for renewable generation**

TNUoS is however not strong enough to deliver onshore wind projects in England under the current planning rules and it is doubtful whether any marginal price signal would be sufficient to overcome the virtual moratorium on wind development in the south. If planning rules changed however TNUoS would be sending a strong locational signal that might have more effect.

As a positive, TNUoS charges is encouraging the Crown Estate to look again closely at further lease rounds in the Celtic Sea and off the south coast of England.

A two key problem with TNUoS, and other forward price signals, is the degree to which the cost signal is a) truly cost reflective and b) the degree to which it is also aligned with the overall forward energy strategy and spatial plan.

One interesting reform proposal which has been proposed by Scottish Power, called OPTiC,[68] would be to recalculate forward TNUoS charges using an algorithm based on a forward forecast of future network constraints using an LMP type pricing model.

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

“ Misalignment between locational signals and energy strategy also known as the “locational signal paradox”. It makes sense to send a strong negative locational signal to dissuade load in areas of network constraint, until a strategic decision is made to invest in network capacity, then the locational signal makes no sense and may need to be flipped.”

Regen, 2024

Since this forward constraint pricing model would include future plans for the deployment of demand and generation, and grid investment, the algorithm would reflect future constraint costs and losses, and also energy strategy. Assuming that the future grid and generation plans are in fact aligned and represent the Strategic and Spatial Energy plan for net zero.

Regen’s view is that this option is worth further consideration and a full study.

Regen recommendation:

Regen’s view is that a combination of strategic planning and alternative locational signals can provide effective investment and siting signals, and that in many respects these signals are already present, albeit imperfect.

We would also challenge the view that a locational marginal price signal can be effective to inform locational decisions of projects that can take 10 or more years to develop.

More work is needed on TNUoS and DUoS reform and we recommend that DESNZ and Ofgem focus on these with the intention to provide locational signals that are cost reflective and aligned with the GB energy strategy and spatial plans.

The OPTIC proposal that has been made by Scottish Power is interesting and should be considered.

Transmission network access arrangements

Regen is not supportive of a shift to non-firm access arrangements for all existing and new assets that is likely to be required in a shift to zonal wholesale markets. This would undermine business models and investment in GB sector at a crucial time for the deployment in the sector. It would also send bad signal to investors in these projects and potentially increase the cost of capital and generally reduce investor confidence in GB energy projects.

There could be a case made for new assets being connected to be done so on a non-firm basis with transparency to the market on the implications of this for ancillary service provision and wider revenue opportunities upfront. This would need to be done over time and in alignment with the wider grid connection reforms that are ongoing. Overall, members are already dealing with significant delays from network operators and a large amount of grid connection/queue management reforms. Trust in the network operators ability to deliver these reforms is low in the industry and we feel that this change would further undermine confidence.

As mentioned earlier, the industry would like further information on the wider impacts on new and existing distribution connections from a shift to non-firm transmission access rights and the introduction of a zonal wholesale market.

Q24. Do you agree with our proposed steps for ensuring continued system operability as the electricity system decarbonises? Please detail any alternative measures we should consider and any evidence on likely impacts.

Regen believes that the case for a zonal pricing market design has not been made and, given the level of design uncertainty and investment risk such a re-design of the market would entail, DESNZ would be justified in dropping the zonal option.

Challenges to system operation

It is clear from the REMA consultation and stakeholder engagement sessions that there is a very strong case that the GB wholesale market, ancillary markets, balancing mechanism and system operation process require both reform and investment in areas such as IT, systems and digitalisation.

This is evidenced by periods with high levels of re-dispatch, volatility in system prices, increased balancing risk for participants, and a rise in both constraint management and balancing costs. 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 action taken by the system operator has a higher price tag.

A further sign of market tension and inefficiency has been the recent appearance of increasing negative day-ahead wholesale prices which have been partly the result of distortions caused by subsidy schemes, as well as a lack of liquidity in short-term markets. Negative pricing may not be a problem in itself and can send strong market signals, but its impact on system operation and the ability of the ESO to predict and respond to changing energy balances needs to be addressed.[69]

These system operation challenges have led to calls for more radical market reform, including LMP, which would also entail a shift back to a more centralised dispatch and push some operational risk, such as constraint management, into the wholesale market.

An alternative view is that rather than a step back to centralised dispatch and mandatory trading markets under LMP, the market reform must support both an efficient liberalised wholesale market and efficient system operations. Market transparency is a key reform are along with improved control room functions, enhancement to the BM, alongside new balancing and constraint management services.

Regen's view is that the current market is not broken but that significant reforms and enhancements to the market and system operation processes are needed. The basic building

[69] Operability including frequency control, stability, inertia, constraint management, reactive power, reserve power etc. For a good description see Day in the Life of the Energy System 2035

blocks of an efficient market are there but at times the market and system operation are misaligned. It also lacks transparency, for participants and the system operator, in key areas such as intra-day bilateral trading and during negative price periods.[70] There is cross-industry consensus that both market and operational systems, data and processes need to be upgraded and further digitalised.

Opportunities for progressive market reform

The REMA consultation process, workshops and engagement events have highlighted a very large number of potential incremental reforms that could be implemented within the existing national market arrangements. Taken together this would constitute a very significant and far-reaching package of reforms, which would present its own implementation, governance and coordination challenges, but could be implemented more quickly and with less risk than more radical re-design options.

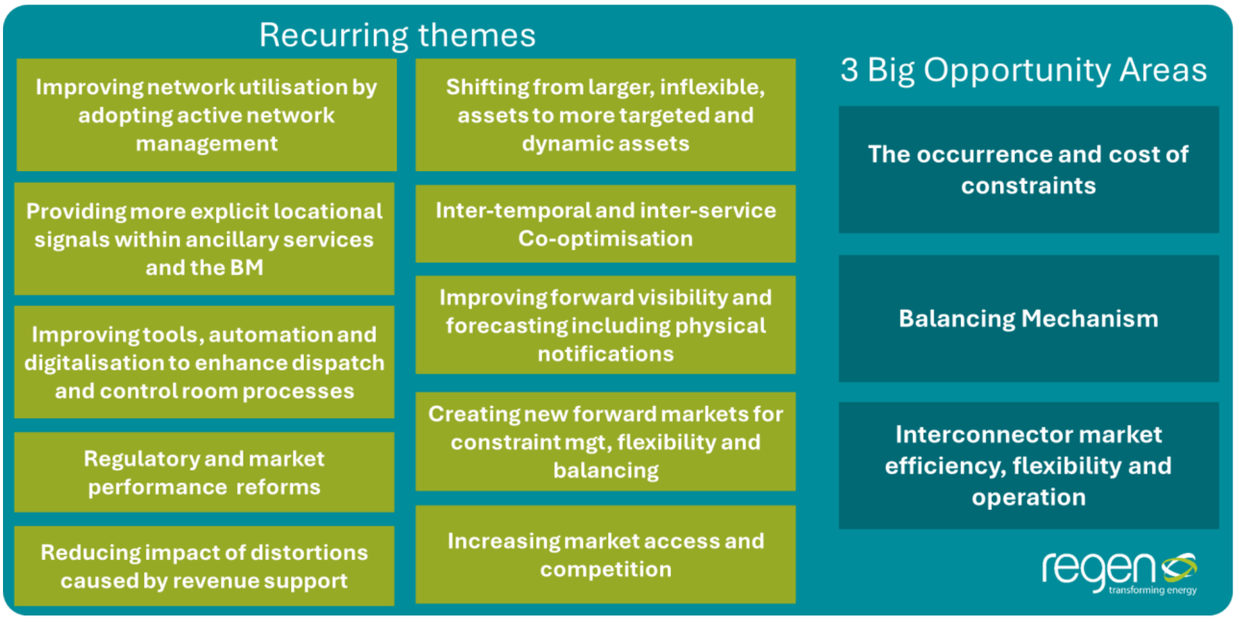


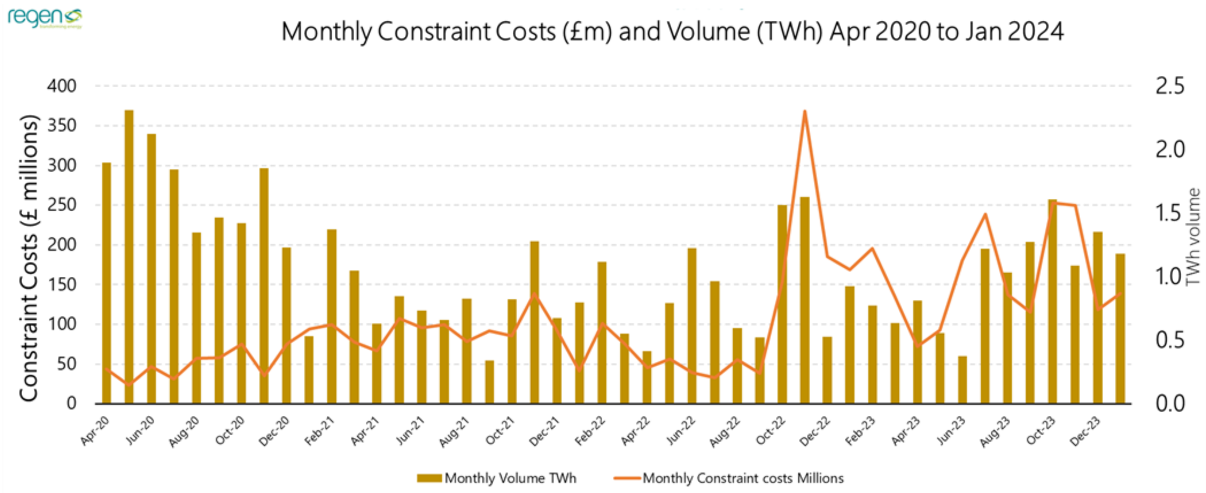
Figure 20**: Recurring themes and opportunity areas for progressive market reform**

Constraint management

The rise in constraint management costs was the main driver to look at radical market reforms such as LMP and red flags raised by the ESO that the current 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 on constraint management costs has been mainly caused by a) a very steep rise in wholesale prices over the energy crisis period and b) the continued reliance on large, and inflexible, gas fired power stations.

[70] A good example of a loss of transparency occurred during a negative price period on 29th December 2022 when three offshore wind farms that were expected to be offline for six to eight hours began generating after 45 minutes.



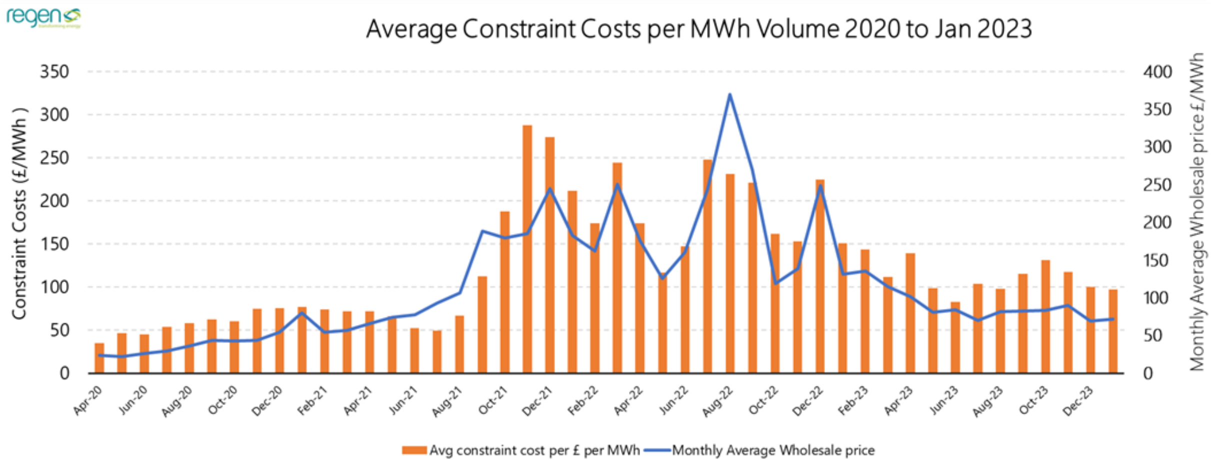


Figure 21: **Rise in constraint management costs, and wholesale prices, Apr 2020 - Jan 2024**

Regen, along with other stakeholders examining constraint costs, has pinpointed numerous reforms, process enhancements, and market advancements capable of diminishing, though not entirely eradicating, both the frequency of constraints and the expense of managing them.[71,72] Many of these ideas and proposals 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.[73]
2. Improvements to forecasting and measures to improve and incentivise more accurate physical notifications.[74]

[71] Examples of Regen studies include Seven Solutions to reduce Constraint Management Costs and evidence given to the ESNZ Select Committee.

[72] See for example analysis by Dr Simon Gill Simon Gill - Exploring options for constraint management in the GB electricity system and by Frontier Economics Reform options for electricity balancing arrangements in Great Britain

[73] The current CMIS reported by the ESO has produced £80m in cost saving in its first 10 months of operation

[74] ESO, 2023. Forecasting Stakeholder Working Group.

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 balancing mechanism so that it creates a market for flexibility providers to bid for what would otherwise be constrained generation.75

The current ESO Open Industry Collaboration Project has produced over 30 idea responses.[76] Several of these responses, 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 resorting to turn down generation.

Some degree of constraint is inevitable and even desirable as it would not make economic sense to build a grid so large that they 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 flexibility, are actioned in markets that are truly competitive and in the absence of gaming, manipulation or other forms of market power.

A key challenge for the system operator right now is that the bulk of constraint management actions are still taken through the balancing mechanism post-gate closure, at a time when control room functions are most under pressure, with inadequate IT and digital capability, predominantly using large and inflexible gas generation.[77]

Reforms that could help reduce the cost of constraint management include:

- Expanding access to the BM to storage assets, demand response and other smaller generation plants, to maintain a high degree of liquidity and competitive pressure.
- Enabling the use of smaller, more responsive and flexible, solutions in the BM that can provide constraint management services without creating unnecessary "bullwhip" effects.[78]
- Investing in new IT systems, processes and capabilities to enable the control room to utilise a wider range of assets and dispatch multiple assets and to reduce the "skip rate" whereby more expensive assets are used because of limitations within the control room function.
- 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 (LCMs).

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[75] Similar to the German Government proposed changes to balancing to promote a "Use don't Curtail" principle

[76] ESO, 2024. Thermal Constraints Collaboration Project.

[77] Studies by LCP Delta, Regen and others suggest that CCGT plants still perform over 80% of balancing turn-up actions.

[78] "Bullwhip" can be described as an overresponse to an imbalance caused by the need to run CCGT plant for longer and at high power output than would be needed.

- 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.
- BM reforms and improvements.
- Allowing interconnectors to provide balancing services, as discussed.

A full study should be made of the potential to reduce constraint costs to reevaluate the projected increase in constraint costs in a national wholesale market with a programme of progressive market reform and to help the NESO prioritise investment and market development in this area.

Reform and enhancement of the Balancing Mechanism

Several of the proposed reforms to the BM have already been highlighted in the previous section on constraint management costs. These include widening the participation in the BM to many more assets and flexibility providers and the 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,[79] have made a significant impact. Modo Energy has estimated that these changes have coincided with a 100% increase in battery utilisation between Dec 2023 and April 2024.

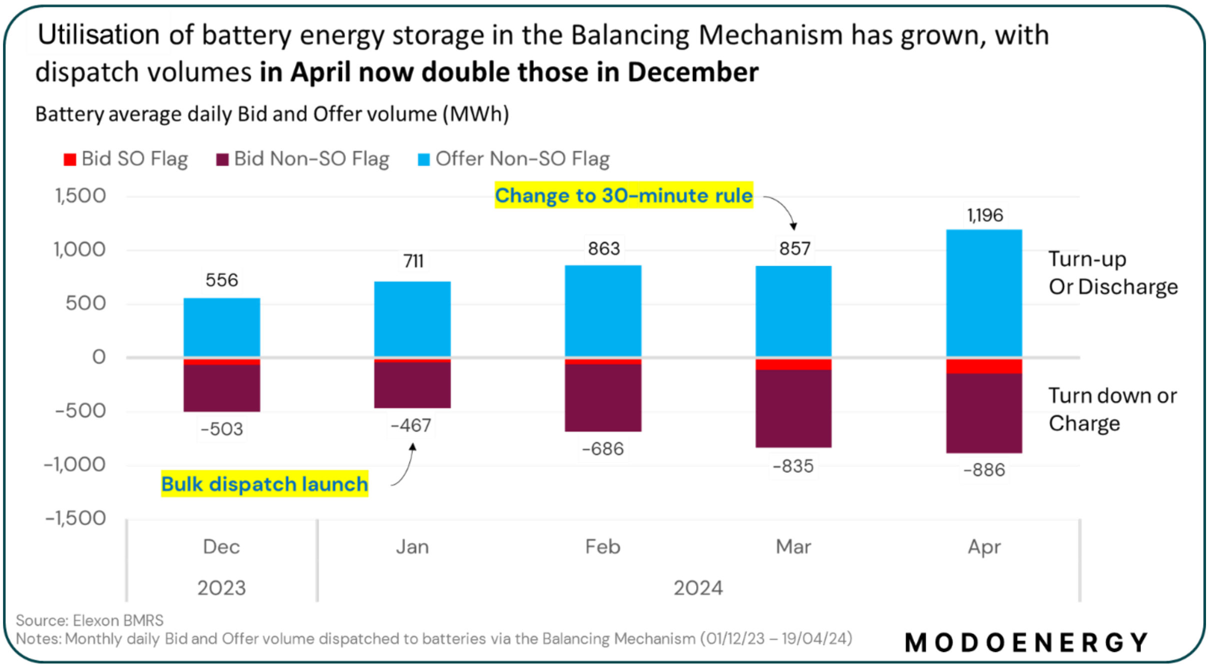

Figure 22: **Changes to battery utilisation in the BM following the implementation of the Open Balancing Platform and changes to the 15-minute rule.**
Source: Modo Energy

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

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 balancing mechanism operated by the 'Control Room of the Future' which would be fully digitalised, highly automated and making use of the latest AI and digital twin technologies such as Virtual Energy Systems.[80,81]

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.[82]

Other balancing reforms that have been highlighted include:

- Measures to increase access, liquidity and 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 capacity market participants within the BM.
- Introduction of more explicit location signals within the BM and other ancillary services to support asset siting.
- Inter-temporal dispatch optimisation across several settlement periods.
- Improved forecast and Physical Notification accuracy.
- Improved asset status visibility; for example, storage, smaller and embedded assets.
- Enabling interconnectors to provide balancing services.

Efficient use of interconnectors

The third big opportunity for progressive operational reform is the efficient use of interconnectors. Interconnectors are expected to 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 – therefore reducing the need for subsidy payments.

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. Therefore, they should be an ideal tool to improve system operation and market efficiency.

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[80] ESO, 2024. Virtual Energy System.

[81] ESO, 2024. Balancing programme.

[82] Inter-temporal dispatch optimisation across several settlement periods is currently a process and market challenge

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

The complexity with interconnectors however is that the decision to invest in an interconnector and then how it is operated in both trading markets and as a balancing function requires collaboration and co-ordination between at least two system operators and two market jurisdictions, and, 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:

- **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.
- Interconnectors may flow into the GB energy system, correctly responding to a national price signal, **but into a part of the grid that is already constrained** thereby adding to 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 for a 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.
- Since Brexit and the Trade and Cooperation Agreement (TCA) **there has been a de-coupling of GB interconnectors from the wider EU energy market**. Although this varies between interconnectors,83 as a practical consequence this means that trading across GB interconnectors is less efficient and can require separate transactions to trade capacity and volume.
- The GB system operator does have some ability to affect interconnector flows (for example through forward counter-trading) and does indeed 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.

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

[83] 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.

Frontier Economics for Scottish Power has highlighted some of these solutions.[84] Analyses are currently in progress and will be published shortly.

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

1. **Improving GB strategic planning and cross-border cooperation for interconnectors:**
    - Develop a UK Integrated Circuit (IC) strategic plan aligned within the SSEP and CSNP.
    - Develop a UK Integrated Circuit (IC) strategic plan aligned within the SSEP and CSNP.
    - Shift from developer led to strategic development.
    - Review the methodology and benefits case analysis used to approve GB interconnector revenue support.
    - Re-engage with EU (ENTSO-E) IC Offshore Network Development Plan and ACERS.
    - Build on bilateral collaboration agreements e.g. GB Island of Ireland energy cooperation MOU.
2. **Improve interconnector market efficiency:**
    - Recouple with EU trading markets.
    - Align GB and IC trading timescales and markets.
    - Re-align GB-ETS /EU-ETS carbon pricing.
    - Establish intraday trading across all ICs.
    - Standardise interconnector trading arrangements and processes.
3. **Manage interconnector flows and enable interconnector balancing:**
    - Greater SO-SO collaboration and coordination.
    - Enhance and enable SO-SO countertrading – energy and capacity – for example looking at how TSO's in Germany and Denmark manage IC flows.
    - Enhance and enable SO-forward market counter trading.
    - Rejoin EU balancing arrangements to allow IC balancing services.
    - Enabling ICs to contribute flexibility potential.

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.

Shorter settlement periods

Regen is supportive of a shift to shorter settlement periods. The industry has been asking for reform to settlement periods for years and we were happy to see this type of reform included in this second consultation. A move to a 15 minute period is a reasonable starting point. We believe that a further shift to 5 minute settlement period could also be warranted in the near future.

[84] Frontier Economics, 2024. Reform options for electricity balancing arrangements in Great Britain.

Regen recommendation:

DESNZ to work with industry on the introduction of a shorter settlement period.

Gate closure

We were disappointed to see that gate closure shortening has been provisionally discounted in the short to medium term in the REMA process. The impact of shorter settlement periods will be significantly reduced if there isn't any corresponding gate closure reforms.

The point made in the consultation regarding shortening gate closure was of some concern:

"could reduce the ESO's ability to balance the system efficiently and economically and may have security and safety implications."

We understand that there would be significant system and IT changes needed at ESO in order to deliver a shorter gate closure. However, we do not believe that security and safety implications should be used as a reason to delay this crucial type of reform.

Regen recommendation:

DESNZ to re-introduce gate closure shortening as an option in the REMA reform timescales.

Additional ancillary services

In the Carbon Trust Report on the Role of Ancillary Services to Encourage Low-carbon Operability,[85] some new ancillary services were highlighted as warranting further investigation. These include the strategic cycling and short-term (shock absorber) constraint reserve services proposed by Zenobē Energy. A strategic cycling service could help cost-optimise curtailment actions over longer constraint periods (e.g. 24 hours or more) while a short-term constraint reserve service could reduce costs when constraint periods are shorter and help manage short-term spikes in renewable output.

These new ancillary services which could be provided by low-carbon flexibility have to the potential to reduce curtailment costs and assist ESO in balancing the system during constraints. We are broadly supportive of further investigation into additional ancillary services that can support new low-carbon flexibility coming online.

Regen recommendation:

DESNZ and ESO to investigate development of additional ancillary services to support the development of further low-carbon flexibility capacity.

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[85] DESNZ, 2024 Report on the Role of Ancillary Services to Encourage Low-carbon Operability

2.6. Options compatibility and legacy arrangements

Responses to questions 25-28

The final section of the consultation provides an initial insight into DESNZ's thinking about key cross-cutting principles that will need to be considered when making final decisions. The discussion of compatibility is crucial as individual reform options will not be implemented in isolation but as part of a wider package of reform. Similarly, the principles which DESNZ use to make decisions on legacy issues will be critical.

At this point, Regen is concerned that insufficient thought has been put into the compatibility and legacy arrangements. We appreciate the challenges associated with doing so; individual reform options need to be developed in a level of detail that we have not yet seen so far before, it is not clear how they would interact with each other, and the options for grandfathering legacy schemes need to be addressed.

Q25. Which market actors (e.g. generators, suppliers, consumers, government) are best placed to bear/manage different types of risk?

The allocation of risk is one of the central considerations of REMA. The scale and type of risk is changing significantly as we move towards a net zero system. As noted in the consultation, there an important principle that risk should sit with those best able to manage them. However, this principle is not sufficient on its own to answer the question of risk should be allocated under REMA.

In particular, Regen thinks that significantly greater exploration is needed of the risk faced by consumers and the role of public energy system institutions – the government, the ESO and Ofgem – in managing that risk. Consumers, as one of the main ultimate beneficiaries of the energy system, inherently need to 'take risk' in order to benefit from the reward of developing a better system in future. This is often done through decisions taken on behalf of consumers and society by the public energy system which consider benefits that accrue over several decades. However, whilst there has been significant focus on ensuring public energy system institutions minimise system cost, there has been much less focus on the appropriate management of consumer risk, a role that is central to ESO and Ofgem's activities.

The consideration of risk also needs to consider the changing type of risk faced by the system. A key element of the change is a change in the balance of fixed and variable costs. A net zero system, in comparison with one based on fossil fuels, has a significantly higher fraction of overall system costs tied up in fixed costs, particularly up-front investments, with a lower fraction in variable operational costs. This can be illustrated in terms of Levelised Cost of Energy (LCoE) as shown in Figure 24. For a CCCT, fixed costs represent only 11% of the total LCOE whereas for an onshore wind farm fixed costs represent around 95% of the total.

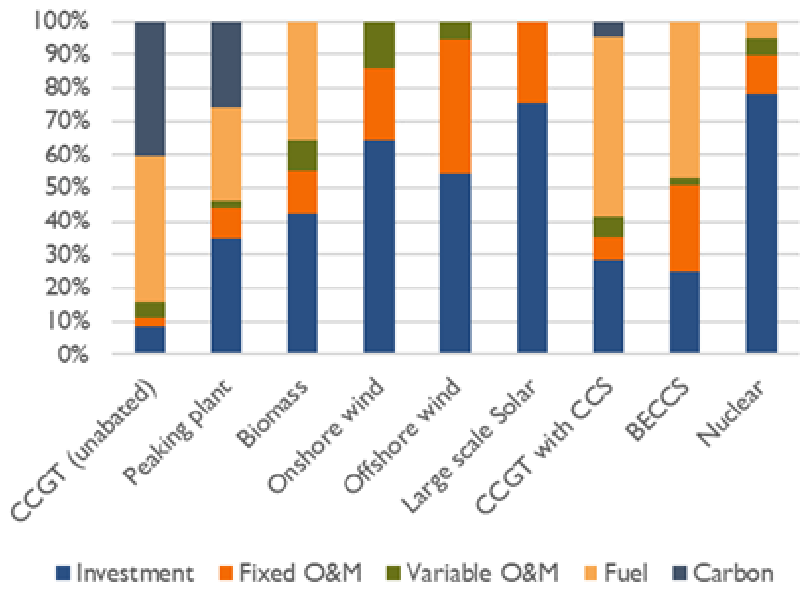

Figure 23**: Breakdown of the Levelised Cost of Energy into fixed and variable cost categories**
Source: BEIS Generation Cost Report, 2020

This change creates both opportunities and risks for investors and for consumers. Firstly, on the opportunities: by moving to a system where the majority of costs are fixed upfront we benefit from much higher costs certainty for each unit of electricity generation. Consumers are less exposed to uncertain future fuel costs, and we can plan for a market system that allows fair recovery of fixed costs over a significant fraction of the operational life of each asset.

However, the move towards fixed costs also creates challenges. The largest component of fixed costs is related to upfront investment which is affected by the cost of capital. An increase in the cost of capital for an offshore wind project where 55% of total costs are related to the initial investment, will have a much bigger impact on the LCoE than an equivalent increase in the cost of capital for a gas power station where the initial investment is around 9% of the LCoE.

Beyond these specific points, Regen thinks that it will be important to take a systematic approach to assessing risk across different REMA options.

Regen recommendation:

As the remaining REMA options are developed in more detail, we recommend that DESNZ work with industry to develop a systematic typology and assessment framework for risk to allow different option-packages to be consistently assessed. We think that given the centrality of risk allocation; such a framework will be critical in ensuring good final decisions are made.

Q26. Do you agree with our initial assessment of the compatibility between our remaining options? Please set out any key interactions we have missed.

Regen does not agree that the consultation has identified the appropriate interactions. This is because the consultation has not presented a systematic review. Instead, it discusses several specific instances of interactions such as the interaction between wholesale market design and CfDs. As such we do not agree that the consultation provides sufficient evidence to conclude that there is a 'high degree of compatibility'.

Regen recommendation:

DESNZ should undertake a systematic compatibility review in which sets of options across the different domains (wholesale market design, low-carbon support mechanisms, flexibility etc.) are assessed as on a scale ranging from 'high synergy' to 'incompatible'. In doing so, DESNZ and industry should create a set of well-developed packages in which it is possible to understand how the nuts and bolts of different options would develop.

Q27. Do you agree with our approach to assessing the impact of REMA reforms on Legacy Arrangements?

Addressed in Q28.

Q28. What risks do we need to consider with regard to Legacy Arrangements, and how can they best be mitigated?

The consultation proposes to take a scheme-by-scheme approach to legacy arrangements. Regen supports this approach and agrees that the specific context and impact of each scheme needs to be considered individually. We also agree with the proposal to consider both functional and financial effects and would also suggest that DESNZ considers system and project effects separately (where project effects include impacts on investors and operators).

In terms of risk: Regen's view is that the biggest risks come from reforms which set up market frameworks that are incompatible with legacy arrangements in their current form and would therefore need at least some changes.

The management of legacy arrangements represents one of the most difficult issues associated with REMA. The long-term nature of support mechanisms means that much of our electricity infrastructure has been developed through support mechanisms which were needed for projects to achieve a positive final investment decision, either through ensuring sufficient revenue or capping risk. And while changes to the law or to regulatory arrangements could remove the benefits of those scheme, even for some existing assets, investors feel they have a legitimate expectation to have those agreements honoured.

Over time we have seen the form of support arrangements change to reflect the growing awareness of the risk decisions that seemed sensible in one context can look very different in another. We moved from ROC payments – which effectively provide a significant additional revenue on top of the market *regardless of the market price* – to a CfD scheme which provides a hedge to consumers as well as support for generators. Later we adapted the CfD scheme, for example through the introduction of the negative pricing rule, to further nuance the distribution of costs. The result is that more recent support mechanism, namely the CfD scheme post AR4, does not suffer the same issues as previous schemes. This was made clear through the price crisis where ROC supported generators received significant windfall gains as a transfer from consumers, whilst CfD generators did not.

When reviewing legacy effects, it will be important to identify the materiality of any impact associated with maintaining existing arrangements. This should include the potential impact under a range of different future scenarios as well as the length of time for which the support mechanism will remain active. For example, ROC support will begin phasing out from 2028.

An important consideration that DESNZ need to be aware of when making any changes to arrangements is the impact of investors' perception of regulatory risk within GB. Over the past decade GB appears to have enjoyed a positive reputation among investors, particularly due to the stability provided through CfD scheme. This stems from a perception that GB has relative regulatory stability and confidence that arrangements entered into with public energy system institutions will be honoured.

Where REMA reforms require a change in existing arrangements, it will be critical that changes are developed alongside detailed discussions with investors. The perception of regulatory risk is very difficult to quantify, however that does not mean it doesn't exist, and maintaining the perception that it is low will be critical in drawing in investment in an environment with GB is increasingly competing with a global market for investment.

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