REMA CONSULTATION RESPONSE

Aurora Energy Research Response: Review of Electricity Market Arrangements (REMA)—Second Consultation

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Introduction

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About Aurora Energy Research

Aurora is the largest dedicated power analytics provider in Europe, made up by a diverse team of over 650 experts with vast energy, financial, and consulting experience. We are a widely used provider of independent market analysis, trusted by over 850 subscribing companies. Our close proximity to clients gives our analysis the edge for major investment, strategic, and policy decisions.

Key themes

There is an immediate need for significant reform to the power market and are pleased to be given the opportunity to present our opinion.

We have responded to questions where we feel most strongly and have an informed view given our extensive market forecasting experience as well as our ongoing interactions with our client base, which includes project developers and financiers across the industry. Our analysis has been shaped by our prior reports including the Multi-Client Study titled 'Locational Marginal Pricing in Great Britain'. The Department for Energy Security and Net Zero and Ofgem were observers of this study. For the avoidance of doubt, this consultation response reflects the views of Aurora and not our clients.

We have outlined greater detail throughout each response but would like to stress the importance of two factors which we believe are just as important as any individual reform proposed in the consultation:

1. The urgency at which decisions must be made if decarbonisation targets are to be met—it has been almost two years since the first REMA consultation, and ongoing uncertainty chips away at investor confidence, and slows the rate at which new developments can take place.
2. The importance of assessing market design holistically and considering the multiple knock-on effects of each decision—the complex nature of the electricity market creates a cascade of interdependencies, which can lead to unintended consequences.

Question Responses

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

We agree with the challenges that have been identified in the consultation. We would like to raise the issue with the budgetary process, which has so far not been addressed and emphasise the issue of distortive dispatch behaviour.

Reference price methodology and budget allocation

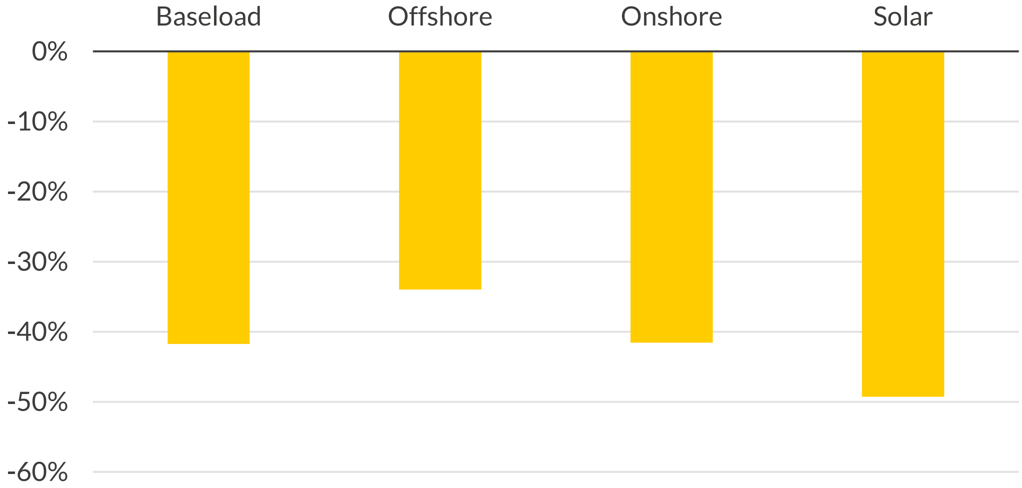
The method in which CfD capacity is allocated is currently inconsistent with government capacity targets. Whilst the government is aiming for 50GW of offshore wind capacity by 2030, the CfD auction clearing mechanism is calculated based on a budget which has no capacity guarantees.

To procure a volume of capacity more consistent with government targets, the reference price methodology could be reformed to align with more realistic market outcomes. Reference prices have been consistently below market prices, which overstates the budgetary impact of each asset, and as a result reduces the procurement of renewable capacity.

For example, the AR6 reference prices in 2030/31 are between 34% and 49% below the renewable capture prices from Aurora's Net Zero scenario (a scenario where the power market reaches net zero emissions by 2035). The delta highlights the budgetary impact of each of these technologies is overstated and therefore more capacity could be procured with limited budgetary impact.

AR6 reference prices relative to Aurora Net Zero

%, 2030/31



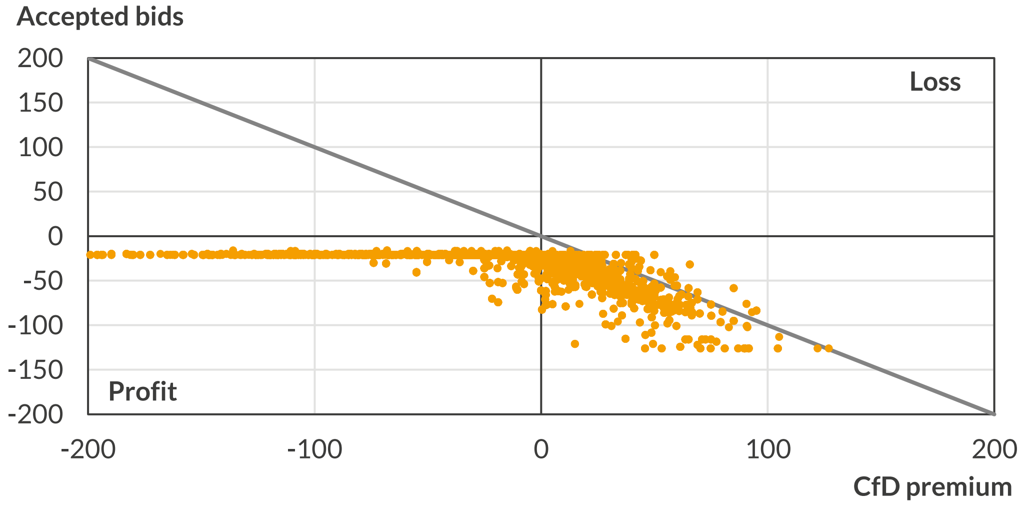
Distortive dispatch behaviour

As identified in the consultation, under the current scheme CfD assets are not incentivised to operate in a manner that supports the system. We believe the main sources of distortions arise because:

1. Generators are always incentivised to maximise metered production to maximise subsidy payments, even in times when the system is long (where production exceeds demand).
2. Generators' behaviour in other markets is distorted as the market premium/clawback is known ahead of power delivery. This creates an artificial short-run-marginal cost when bidding into markets following the day-ahead market, which leads to higher intraday, balancing mechanism, and ancillary market bids, which are not dependent on the true marginal cost of the asset providing these services. This results in greater costs for consumers.

   We have analysed the performance of two CfD supported assets in Scotland within the balancing mechanism during 2022/2023 and found that accepted bid levels are dependent on the CfD top-up payment, rather than the true marginal cost of reducing generation.

Accepted BM bids vs. CfD premium
£/MWh



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

We believe assets would change their behaviour if provided with the correct incentives by:

- Adjusting dispatch behaviour in intraday/balancing mechanism/ancillary services markets.
- Adjusting the location of new developments, subject to the parallel provision of alternative locations (including for offshore wind, grid connections and seabed leasing).

Both the deemed and capacity CfD options would be effective at altering the dispatch behaviour of CfD assets. Bidding in the intraday, balancing, and ancillary services markets would be made similar to a purely merchant asset as subsidy payments are made irrespective of metered generation, therefore the artificial short-run marginal cost of assets bidding into these markets would be removed.

However, there is no way to fully remove distortions within the CfD mechanism as subsidised assets, by design, will never truly operate in the same way as a purely merchant asset. A deemed CfD asset faces different opportunity costs than a fully merchant asset when participating in an ancillary service that might limit opportunities for future wholesale dispatch. Furthermore, not all distortions are created in dispatch, and issues created in investment decisions driven by land, seabed, planning and grid connection constraints also impact when and where energy will be generated.

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

Under the deemed methodology it should be emphasised that generators are never incentivised to accurately report generated volumes and therefore there will always be a risk of gaming. When the market price is below the strike price assets are incentivised to maximise deemed volumes to maximise top-up payments. When the market price is above the strike price assets are incentivised to minimise deemed volumes to minimise clawback payments.

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

	Deemed CfD	Capacity CfD
Benefits	▪ Removal of dispatch distortions in intraday, balancing, and ancillary service markets. ▪ Deeming payments represents an incremental change to the current methodology, so a smaller adjustment to the business case is needed for assets currently under development. ▪ CfD payments for renewable generation remain fully hedged for consumers. ▪ Removal of volume risk for generators during periods with negative prices.	▪ Removal of dispatch distortions in intraday, balancing, and ancillary service markets. ▪ Potentially greater upside for developers in the event of higher market prices, dependent on the consumer protection mechanism. ▪ Simple capacity payment avoids the need for a deeming methodology. ▪ Could encourage more creative business models, for example through co-location and revenue stacking.
Risks	▪ Deeming methodology is prone to gaming as assets are incentivised to maximise/minimise reported generation volumes.	▪ Greater change to existing scheme risking a delay to the delivery of projects currently in the pipeline. ▪ If generators only pay back a proportion of the difference between the wholesale reference price and an administrative maximum, consumers are not fully hedged against rising power prices.

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

The financial risk of implementing minima for the capacity market is that the market will pay a higher price for firm capacity than it would in a simpler auction design. It is also possible that, through price discrimination, the market operator can reduce the overall spend on firm capacity. We have focussed on the operational concerns of such reforms and potential inefficiencies they might introduce into the CM.

We think attempting to procure low carbon generation via the CM risks diluting the efficacy of the CM, with limited benefits to decarbonisation. Carbon emissions are created via generation, and not by capacity. As such, low carbon power will likely come to market via subsidy schemes that impact both generation and capacity, rather than solely through the CM. The concern expressed in this consultation about the adequacy of the current unabated gas fleet, along with recent signals indicating that more firm capacity is needed in the immediate future, suggest that cost-effective operation of the CM will be crucial in the coming years. Our own analysis has highlighted that a mix of technologies are required to address the security of supply issues and that low carbon solutions alone will be challenging to deploy in time to meet the pressing security of supply requirements.

There is no "silver bullet" technology that will ensure security of supply

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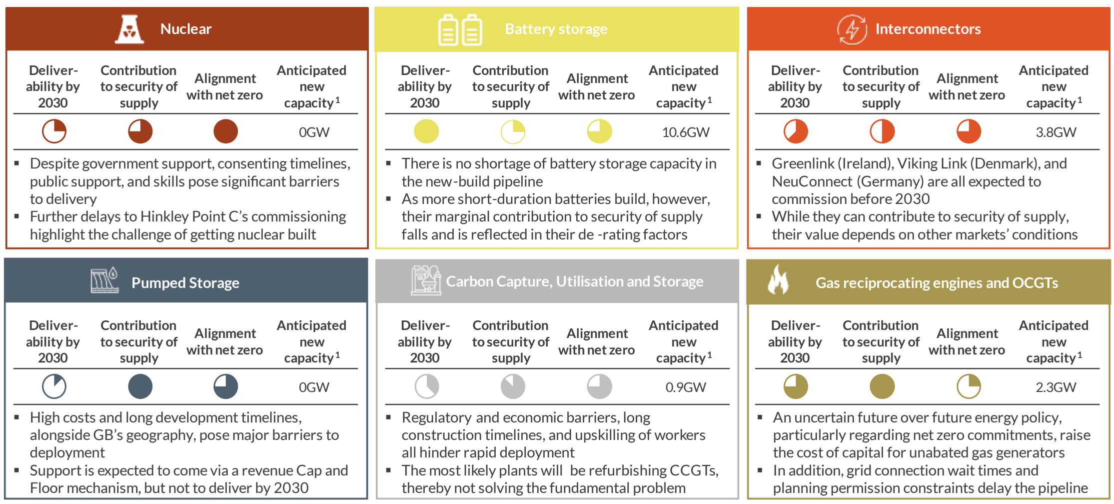


1) Nameplate capacity, by 2030 in Aurora Central.

Source: Aurora Energy Research, EDF

The deployment of low-carbon firm capacity is expected to be done almost entirely through separate, bespoke subsidy schemes, similar to the cap and floor schemes for interconnectors and potentially for LDES, the CfD/RAB schemes for nuclear and DPA scheme for CCS capacity. This is because firm, low carbon options like CCS and hydrogen will not be competitive with unabated gas at current market rates, so will require bespoke subsidy arrangements to ensure that plants are dispatched. This reflects the reality that securing power sector decarbonisation relies on procuring low carbon generation and not simply low carbon capacity.

The recent Hydrogen to Power Consultation noted that a split CM was unlikely to bring hydrogen generation to market and that we do not feel sufficient evidence has been presented to answer the same concerns about a minima-based market design.

In the Long Duration Energy Storage consultation, to which we also submitted a response, we note regulators highlighted that "even with these reforms [to the CM], the CM is unlikely to be able to offer the required revenues necessary to increase and encourage private investment in developed LDES technologies because of the high upfront capital costs."

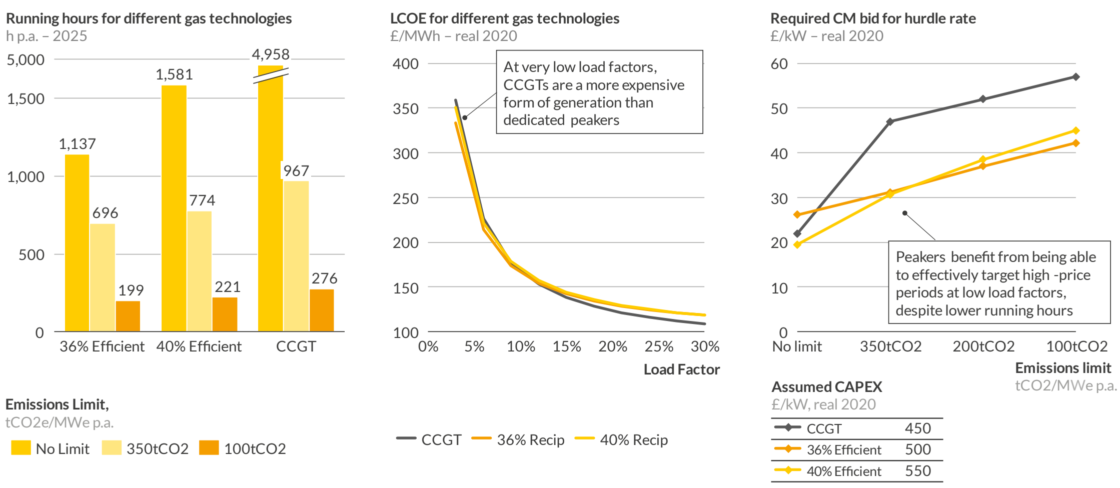
DESNZ has explicitly expressed scepticism that the CM can deliver major forms of low carbon firm generation in the next decade. This casts significant doubt that measures aiming to procure a minimum of firm, low carbon capacity via the CM will be effective at this time.

There is a stronger argument for setting minima for specific flexibility characteristics, such as dispatch duration. We would like to note however that there is a rapidly increasing administrative burden involved in setting multiple minima and that a single asset may qualify for multiple clearing prices, which increases the gaming risk of the auction. This would be especially true in cases where the minima are low relative to the overall auction size and the size of assets. As such, we feel that the number of capacity minima for the CM auction should be kept to the minimum level possible.

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

We believe that there is a substantial risk in enforcing annual emissions limits on new-build capacity. The enforcement of these limits can only increase carbon emissions for a given capacity mix, as the carbon emissions of a plant are directly reflected in that plant's marginal cost via the UK ETS. Therefore, if a plant is limited in dispatch because of an annual limit on emissions, then the most likely consequence is that a less efficient plant will be utilised, producing greater carbon emissions and higher costs. In terms of capacity mix impact, research we conducted in 2021 suggested that annual emissions limits would structurally favour cheaper and less efficient capacity with lower costs, relative to more efficient peaking plants. Cheaper, low-efficiency capacity would be favoured at annual emissions limits of around 350tCO_2/kW or less.

An emissions limit defined on the basis of annual total emissions would favour cheaper peaking technologies



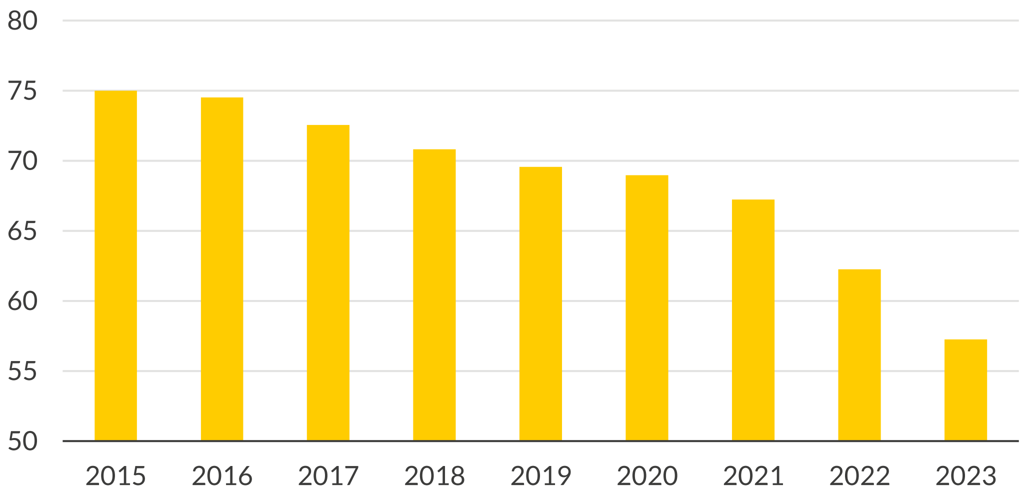
There is a separate consideration that reducing per MWh emissions limits could lead to the deployment of low-carbon capacity. This is a strong argument in favour of more stringent limits, especially for the deployment of hydrogen or CCS capacity. However, it remains likely that this capacity will not be brought to market by the CM in the near term, so any capacity mix impact will be muted. Such a reform could be a meaningful step in decarbonising the CM in the future, but the rationale for implementation in 2026 is not clear.

The main impact of such limits would be to preclude the commercial case for building new CCGT capacity via the CM. However, no new CCGT capacity participated in the latest round of CM auctions, and it is far more likely that this measure will simply lead to the delivery of the same set of capacity (mainly peaking plants) with less efficient dispatch and higher costs, as asset owners will be less confident of future returns under an annual emissions limit.

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

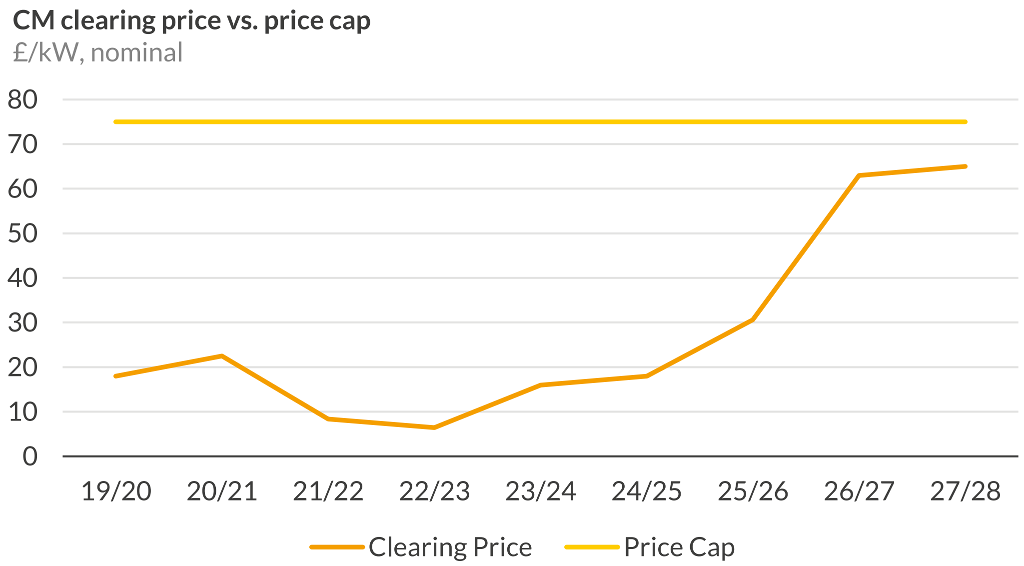
An additional issue with the current implementation of the CM that we would like to highlight is that the CM has retained the same nominal cap since its introduction and that this cap has fallen sharply in real terms, especially recently, due to high and sustained inflation. The value of the CM price cap, expressed in 2015 GBP, has now fallen by almost 25% to £57.26.

Real value of CM price cap
£/kW, indexed to 2015



The consensus among market participants, regulators, and economic forecasters is that GBP inflation, despite falling, will remain above the historic levels since 2013 for the immediate future. As such, we expect this issue to become increasingly binding, and to reduce the investment signal that the CM provides to developers. We note that the latest T-4 CM auction the auction cleared within £10/kW of the cap, suggesting that the cost of new capacity is already approaching the cap in the CM.

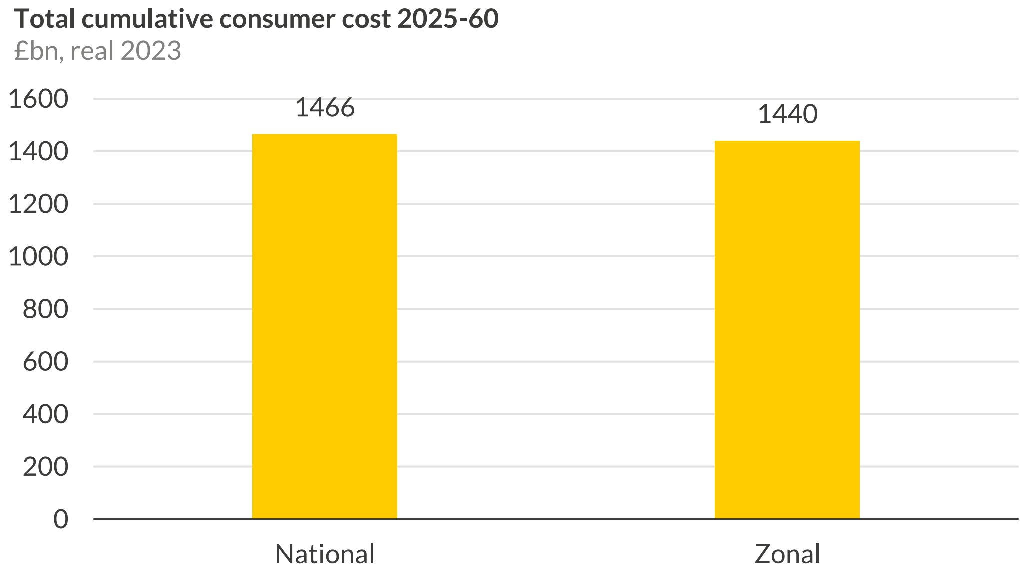
We would like to see some measures put in place to ensure that the CM price cap is being set in a consistent fashion and at a level sufficient to secure investment in firm capacity. This is mentioned in the associated supporting documentation for this consultation, but we would like to see an enduring, systematic approach to setting the CM price cap put in place.



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

We agree with the design choices that have been identified. We have commented on what we see as the most important design factors: number of zones, dispatch, and demand-side exposure. Informing our view is our locational marginal pricing study where we assessed the benefits of a 7-zone wholesale market, assuming the power sector achieves Net Zero by 2035.

Our analysis suggests consumers could save up to £26bn (or 1.7%) cumulatively across 2025–2060 under a zonal pricing regime. These savings increase under a scenario with delayed network deployment, as zonal wholesale prices protect consumers from high constraint management costs and more efficiently resolves transmission constraints. However, these savings could be removed by an increase in the cost of capital, or under a scenario when the power sector misses the 2035 target and reaches Net Zero in 2050. Careful implementation and appropriate grandfathering are now the most important issues for DESNZ to consider in order to maintain market confidence. It remains extremely uncertain how a transition to zonal pricing would evolve and the potential adverse impacts during the transitional phase, which could remove any consumer savings.



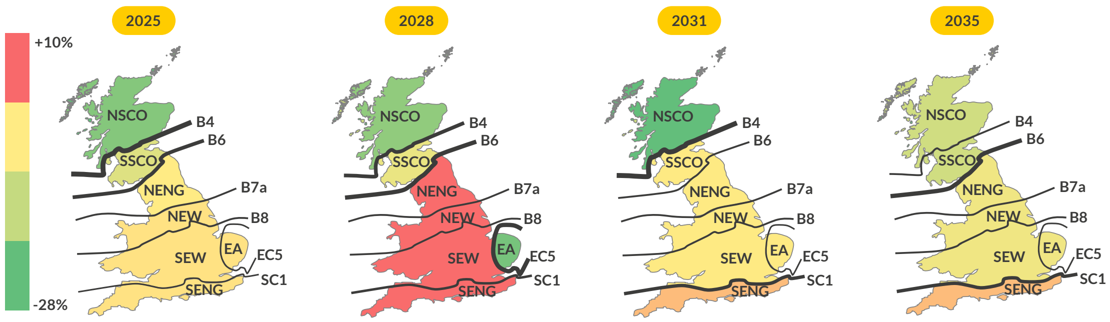
Number of zones/approaches to zonal definition

We believe that the number and location of zones is the most important factor when assessing a zonal pricing system. Any implementation of locational pricing is a trade-off between improvements to market settlement, which captures constraints across key transmission boundaries, and ensuring market conditions are such that renewable and flexible assets remain an attractive route for investment.

We believe a zonal system should focus on capturing the major transmission constraints. If zonal boundaries do not capture critical boundary constraints, such as those between East Anglia and the rest of the UK (the EC5 boundary), then significant volumes of redispatch will still be required. In the current GB power system, the most important boundary is between England and Scotland (the B6 boundary), but there are also critical boundary constraints within Scotland. Our own analysis assumed 7 zones and found significant price differences from accounting for the SC1, EC5 and B4 boundaries, suggesting that a solution as simple as splitting England and Scotland would not capture significant network constraints.

ETYS boundary upgrades significantly reduce zonal price differentials but congestion on the B4 and SC1 necessitates further upgrades

Difference in zonal baseload price vs. national average
%



Line thickness proportional to boundary congestion [1]

1) Congestion measured as congestion revenue (the sum of the price delta across each boundary multiplied by the flow across the boundary); this differs from the congestion metric used in the ETYS, which looks solely at the estimated excess flows across each boundary beyond its capability. Congestion here is also a function of Aurora Net Zero capacity and demand assumptions, which differ to those used in National Grid's Future Energy Scenarios.
Source(s): Aurora Energy Research

Whilst our modelling captures the dispatch effects of different zones, we did not examine the impacts of reduced market liquidity within these zones. It is possible that greater volatility and reduced liquidity would make it more difficult for operators in these zones to hedge their positions, increasing risk and the cost of capital. This has already been noted as a problem within the national pricing system and would be exacerbated with a system with smaller zones. If a zonal pricing model is not going to avoid the need for significant volumes of redispatch, then the overall need for this reform is undermined.

Dispatch

We believe dispatch is an important design choice and must be assessed alongside the number of price zones. Whilst centralised dispatch would be necessary for a system with many zones, this could introduce biases for or against certain assets. For example, currently in the balancing mechanism, imperfect dispatch leads to assets being 'skipped' out-of-merit, which ultimately leads to higher constraint management costs. Avoiding a similar result in wholesale would likely also require complex system upgrades for managing dispatch, with significant risk of implementation difficulties.

Demand-side exposure

We agree the exposure of demand to locational pricing is a key design choice. Northern England and Scotland could see significant increase in data centre demand and green hydrogen production if sources of demand were incentivised to locate in lower price zones close to renewable sources of electricity. Our modelling suggests the cost of producing green hydrogen could be reduced by up to 20% under a 7-zone model, where demand is fully exposed to locational signals, compared to a national pricing system. This could bring significant benefits to the wider economy, whilst simultaneously reducing the strain on constraint boundaries. It is inherently difficult to capture ex ante the potential innovation benefits which arise from clearer market arrangements but more economic location of demand, including the ability to attract growing parts of the global economy to the UK, seem likely candidates for these benefits.