Zonal Pricing, Volume Risk and the 2030 Clean Power Target

UKERC Discussion Paper

Will Blyth (Oxford Energy Associates)

Robert Gross (UKERC Director and Imperial College London)

Phil Heptonstall (Imperial College London)

Callum MacIver (University of Strathclyde)

Magnus Jamieson (University of Strathclyde)

March 2025

Introduction to UKERC

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UKERC is funded by the UK Research and Innovation.

Summary

Volume Risk and 2030

The UK Government is considering implementing zonal pricing in Great Britain's electricity market. This policy shift could significantly impact upcoming Contract for Difference (CfD) auction rounds, critical for meeting its Clean Power 2030 Mission. UKERC is undertaking independent analysis exploring how uncertainty over zonal pricing and transmission capacity expansion affect investor risk and consumer costs.

The Clean Power Mission requires at least 20 GW of new wind power to be delivered in forthcoming CfD Allocation Rounds, much of it in Scotland and Northern England. Connecting this generation to demand centres necessitates major transmission upgrades, which the Clean Power Mission is seeking to accelerate. The Government has promised to decide on zonal pricing before the next CfD auction in July 2025.

UKERC's modelling reveals three key findings:

1. Increased Strike Prices: Zonal pricing could increase strike prices in upcoming CfD auctions by up to £20/MWh, as investors factor in the additional future volume risk that stems from exposure to transmission capacity uncertainty.
2. Higher Consumer Costs: These elevated strike prices could increase consumer costs by up to £3 billion annually, offsetting financial benefits from zonal pricing.
3. Diminishing Future Risk: Zonal pricing risks should decrease over time as transmission infrastructure development unfolds, suggesting that zonal pricing would ideally be introduced after resolving key transmission uncertainties.

The analysis suggests that implementing zonal pricing before resolving transmission uncertainties risks "putting the cart before the horse," exposing investors to unnecessary risks that could negate zonal pricing's benefits. The only alternative to delaying zonal pricing would be fully compensating prospective bidders for volume risk, though it is currently unclear whether or how this could be done.

Moving South

Zonal pricing combined with transmission constraints could reduce generation investment in constrained regions. To illustrate the impact of this we also explore 'Plan-B' scenarios that try to meet the 2030 targets by replacing on/offshore wind in Northern Britain with onshore wind and solar located further south. Three experiments were conducted:

1. Maintaining total renewable generation with onshore wind-dominated southern additions: **This fails to meet CO_2/gas reduction targets.**

2. Meeting CO_2 targets with onshore wind-dominated southern additions: **This significantly increases total new capacity needed, generation costs and GB-wide curtailment.**

3. Meeting CO_2 targets with equal wind and solar southern additions: **Curtailment increases less than Exp. 2, but costs still increase, and even more new capacity must be added.**

More capacity is required because output is less correlated with demand and capacity factors are lower, which also drives increased GB-wide curtailment. Replacing 15 to 20 GW of on/offshore wind in Scotland/Northern England would need an extra 17-33GW of onshore wind and 5-25GW of solar in England and Wales. This would require around 400-800 additional wind farms and 100-500 solar farms – a five-to-nine-fold increase on current installed capacities.

Questions for policymakers

The debate over locational pricing is overshadowing forthcoming allocations of CfDs that will be essential if the CP30 goal is to be achieved. Policy choices around zonal pricing are now urgent, and our analysis suggests the following questions:

1. How acceptable is the risk of a material increase in CfD prices, with knock-on effect on bills, for AR7-9 relative to an alternative where zonal pricing is not introduced?
2. Is a 'plan-B' feasible, such that the 2030 Clean Power Target can still be met, should some investors decline to participate in AR7-9, and/or if bid-prices turn out to be unacceptably high?
3. Is it possible to provide investors with enough information to allow them to develop an informed view of the impact of zonal pricing in time for AR7-9? This might include location and number of zones, rules for trading across zones, market clearing arrangements during periods of oversupply, and any arrangements in place to protect forthcoming and legacy investments.
4. Is it feasible to fully protect AR7-9 investors from the uncertainties created by moving to zonal pricing ahead of build-out of new transmission capacity, to avoid them pricing this risk into their bids, including any measures to protect them from the volume risk that this would entail?
5. How substantial and certain is the 'size of the prize' associated with moving to zonal pricing now (rather than some later date), such that the short-term costs associated with doing so are outweighed by the benefits that could accrue in the mid-2030s and beyond? And related to this, whether a package of incremental reforms could deliver many of the operational efficiencies that zonal pricing provides long-term with fewer negative effects on the CP2030 target.

The 2030 clean power mission is an exceptionally bold endeavour that requires coordinated action across government and industry to mobilise an unprecedented pace of investment in generation assets and transmission capacity. Our analysis focuses on the risks for market participants if Government tries to bring in zonal pricing at the same time. These are substantial and there is no straightforward plan B. The key question is not whether zonal pricing has benefits, but whether the time to introduce it is now.

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1. Introduction

For some time, the UK Government has been undertaking a review of electricity markets, known as REMA.[1] This includes considering a move away from a single wholesale power price everywhere in Great Britain, breaking the country up into multiple zones each with its own electricity price. Zonal pricing has generated considerable debate among stakeholders, with strongly held views and contradictory evidence emerging on both sides.[2,3,4,5,6]

This UKERC Discussion Paper provides initial findings from ongoing analysis using electricity-system and financial risk modelling to help inform this important policy decision[i]. Our research seeks to understand how zonal pricing will impact investor risk in upcoming Contract for Difference (CfD) auction Allocation Rounds (AR7-9). [7] These auctions are critical to the success of the Clean Power Mission[8], a major plank of government policy. Government has yet to reach a decision about zonal pricing. It has promised to do so before the next Allocation Round (AR7) takes place in July 2025.

The Clean Power Action Plan[9] makes clear that large capacities of new wind and solar must be commissioned through AR7-9: at least 20 GW of additional wind power alone. Much of the new wind power is expected in Scotland and Northern England, where wind speeds are high, and sites have already been secured.[10] To connect this excellent wind resource to demand further south, major upgrades to transmission infrastructure are underway.[11]

This is where the debate over zonal pricing intersects with the Clean Power Plan. One of the most significant areas of consumer savings claimed for zonal pricing arises from reducing or removing payments to renewable generators when energy needs to be constrained due to network capacity.[12] The flipside of this is that reduced and/or more uncertain volumes of electricity sales in constrained zones would be expected to feed through into higher CfD bid prices. Since CfD strike prices are set GB-wide, CfD prices across the country could increase.

As a result, removing constraint payments is not costless. Even if future sales volumes in constrained zones were known with complete certainty, a lower volume of electricity sales would be expected to result in a higher CfD price, all other factors being equal. However, since the number and location of zones is currently unclear, and the timing of transmission upgrades remains somewhat uncertain, developers also face considerable uncertainty about future sales volumes. The uncertainty

[i] The methodological approaches used in this analysis are described in detail in a forthcoming UKERC Working Paper. The analysis has been undertaken independently of government and any stakeholders, though we have consulted with industry experts in order to understand key issues such as price formation and routes to market during periods of zero or negative pricing. We are publishing this Discussion Paper in advance of a full description of the analysis in order to ensure that our findings reach a wide audience as quickly as possible. The research has been supported solely through core funds in the UKERC Phase 4 Technology and Policy Assessment theme, and UKERC 2024 – 2029 Responsive Research Theme.

affects developers in all parts of the UK and gives rise to a phenomenon known as volume risk.

The role of CfD prices in consumer bills is set to rise as the share of renewables increases. This can reduce exposure to volatile gas prices, and CfDs offer the potential to reduce household bills.[13] However, higher CfD prices would counteract, at least in part, savings associated with removing constraint payments. Indeed, exposing developers to the volume risks inherent in moving to zonal pricing ahead of transmission expansion could *increase* costs to consumers rather than reducing them. If the ability to sell electricity in constrained zones is reduced, generators may also decide not to proceed with a project at all. The scale of these impacts is the focus of this paper:

Part 1 provides an overview of initial findings of analysis of the impact of volume risk on forthcoming CfD bid prices, and hence consumers[ii].

Part 2 explores a ‘plan B’ scenario, where uncertainty over transmission upgrades and zonal pricing drives investment away from Scotland and Northern England. ‘Moving South’ assesses the extra onshore wind and solar would be needed in England and Wales to meet the 2030 target, and how this impacts total capacity, costs and curtailment.

Part 3 discusses the fundamental economics of high variable renewable systems, and *Part 4* highlights the issues for policy that follow from the analysis.

2. Zonal Pricing, Transmission Upgrades and Volume Risk

Under Clean Power 2030 targets, both renewable energy and the transmission capacity to connect it with demand are scheduled for significant expansion.[14] The geographical disconnect between good renewable resource locations and historical generation sites necessitates substantial new transmission infrastructure development.[15] Britain’s electricity grid was planned and built in the mid-20th century, and reflected the resource base of the time – our one-time coal dominated system required transmission from good locations for coal-fired power to demand centres.

The need for new transmission capacity is established by policymakers based on system needs modelling. A planned approach is adopted in most countries because transmission development involves capital-intensive, long-term investments that require years to complete.[16] [17] A substantial expansion of transmission capacity across the country is planned for the coming decade. Our last remaining coal-fired power station has closed, coal-by-wire of the 1960s is finally over, and we need to

[ii] Our analysis proceeds on the assumption that zonal pricing is announced prior to AR7-9 and without explicit protections against volume risk, such as recommended by the Energy System Catapult. We return to this in our discussion of policy implications, below.

re-engineer our electricity system so that we can exploit the UK's excellent renewable energy resources.

Under a zonal pricing regime, price differentials between zones would directly correlate with capacities of generation/demand within zones and the available transmission capacity connecting them. With unconstrained electricity flows between zones, price variations would be minimal, limiting the impact of zonal pricing. However, transmission investment is being planned so we can access the best renewable energy resources, and it will not be directly driven by zonal price differentials. In a zonal market, transmission capacity is a price-maker rather than a price-taker. Consequently, uncertainty regarding future inter-zonal transmission capacity creates significant uncertainty over both prices and sales volumes within individual zones.

The Government has initiated measures to accelerate transmission development as part of the Clean Power 2030 Action Plan. However, potential investors cannot disregard uncertainties surrounding implementation timelines and the initial operational performance of new transmission capacity once built. This uncertainty presents significant risks to investors, as both zonal prices and renewable generation sales volumes are highly sensitive to transmission capacity development.

Price risk can be largely ameliorated through a local CfD reference price.[18] However, if transmission expansion is delayed or falls short of projections, there is increased volume risk: renewable investors face the risk of being unable to sell their electricity during constraint periods. Under the CfD scheme, payments are only made when plants are self-dispatched, requiring generators to secure a market route for their output. During oversupply periods, not all generators will be able to secure this market access, exposing them to non-dispatch risk and loss of CfD payments. This risk will be most acute in constrained zones under zonal pricing.

The risk inherent in moving to zonal pricing before transmission upgrades are in place is made worse by substantial uncertainty regarding the potential implementation, timing, and specifics of zonal pricing. At the time of writing the locations and number of zones are still to be determined and there is little clarity about protections for existing and forthcoming investments transitioning from the current market structure to this new environment.

Consumer Impacts of Zonal Pricing Uncertainty

Volume risk will increase somewhat regardless of zonal pricing. Our modelling shows that growth in GB-wide renewable generation will periodically create oversupply conditions, which is consistent with NESO analysis.[19] While generators face these risks under both national and zonal pricing models, zonal pricing significantly alters risk distribution between zones. Transmission uncertainty creates volume risks for generators on both sides of zonal boundaries, as delayed or underperforming transmission infrastructure will affect non-dispatch patterns. This specific transmission-related volume risk only exists under a zonal pricing regime.

Such externally imposed risks will inevitably be factored in when developers formulate their CfD auction bids. This has direct implications for consumers, as increased bid prices will raise the overall cost of renewable energy. Consumers ultimately bear these costs through the clearing price mechanism of renewable auctions, where the highest price bid that clears in the auction sets the price paid for each unit of renewable energy generated GB-wide from that auction.

Our analysis shows that the risk exposure is asymmetrical and a function of the scale and pace of transmission build. Only some bidders in regions most reliant on transmission scale up would see the full extent of negative volume risks, but if those units price that risk into their CfD bid and end up setting the auction clearing price, then the consumer cost impact would apply to all successful CfD participants, GB-wide. As we explain in more detail below, in the longer-term and once new transmission and generation capacities are more certain, market participants could respond to volume risk. At the current time, investors face combined uncertainty over policy changes, transmission build and renewable generation expansion.

The nature and scale of this interrelated uncertainty over zonal pricing and pace of transmission build has not been a significant feature in the discourse over zonal pricing. UKERC therefore undertook analysis of the impacts on CfD bid prices and consumers using energy system dispatch and financial modelling under different assumptions about transmission build out.

Our analysis focused on the Scotland-England border, modelling an 'expected' transmission capacity of 10.7GW consistent with the NESO CP30 scenario.[20] We examined multiple scenarios: a reduced transmission scenario assuming a permanent 30% capacity reduction, a delayed transmission scenario where this reduction lasts for five years, and a higher transmission scenario of 13.7GW aligned with the previous Ten Year Plan.[21]

Zonal Volume Risk Findings

Our analysis reveals several critical findings regarding the potential impact of zonal pricing on the GB electricity market:

Finding 1: Increased Strike Prices

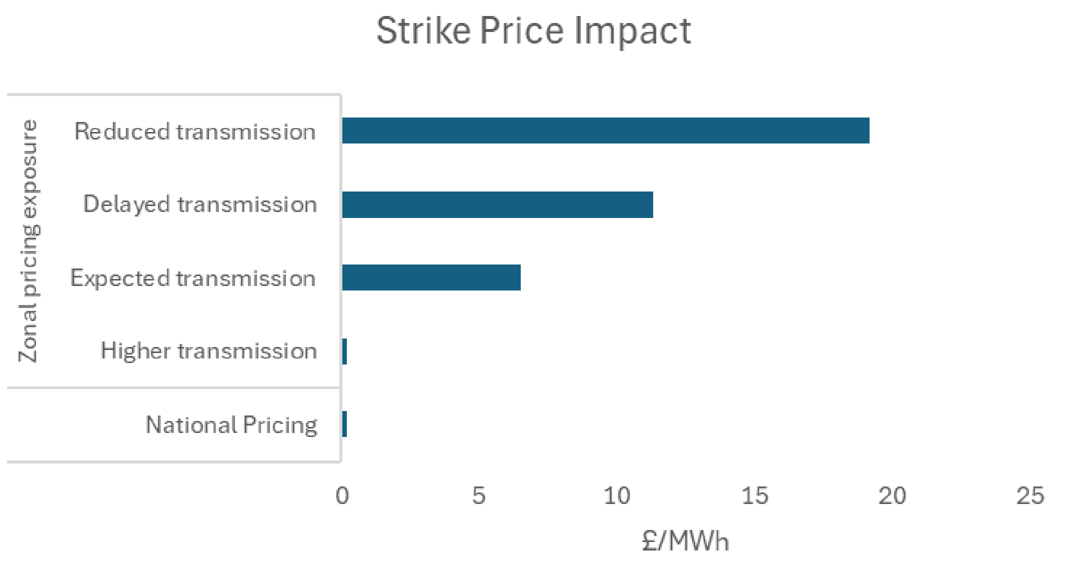

Figure 1. *Effect on strike prices*

Uncertainty surrounding zonal pricing implementation could increase GB-wide strike prices in upcoming renewable energy auction rounds by up to £20/MWh, with concomitant impacts on the costs of achieving renewable energy targets. This increase stems from investors' heightened exposure to transmission capacity uncertainty, prompting them to elevate auction bid prices to cover this risk. Our modelling indicates that strike prices could rise by up to £20/MWh depending on investors' risk perception, including uncertainty regarding protection levels for AR7-9 bidders.

In our analysis we have tried to represent the uncertainty that developers face over progress with transmission upgrades. By using different scenarios, we illustrate how different levels of success and performance with transmission upgrades impacts sales volume and hence CfD strike price. The range we have chosen represents a reasonable spread of possibilities, based upon discussions with stakeholders, but reflects a judgement on the part of the authors. If investors perceive transmission upgrade risks to be higher or lower than these illustrative scenarios, then the impact on strike prices will change commensurately. Should investors expect transmission upgrades be slower than our reduced transmission scenario, the impact on strike prices would be larger still. As the chart illustrates, if investors expect transmission build to go to plan the strike price impacts are much smaller, though not immaterial.[iii]

The principal point of the analysis is that developers will seek to represent a spread of possible outcomes when faced with the unavoidable uncertainty associated with trying to judge the outcome of an ambitious programme of investment in transmission. The analysis is a simplification, that retains an expected level of return in the face of uncertainty, and shows how our chosen worse-case scenario impacts strike prices. However, we believe that it provides a clear and simple indication of the

[iii] In future analysis we will explore the strike price impact in the 'expected transmission' scenario, and other sensitivities relative to increases in constraint payments to generators in the 2030s without zonal pricing.

scale of volume risks faced by would-be developers as a result of moving to zonal pricing whilst the pace of transmission build-out remains uncertain.

Finding 2: Consumer Cost Implications

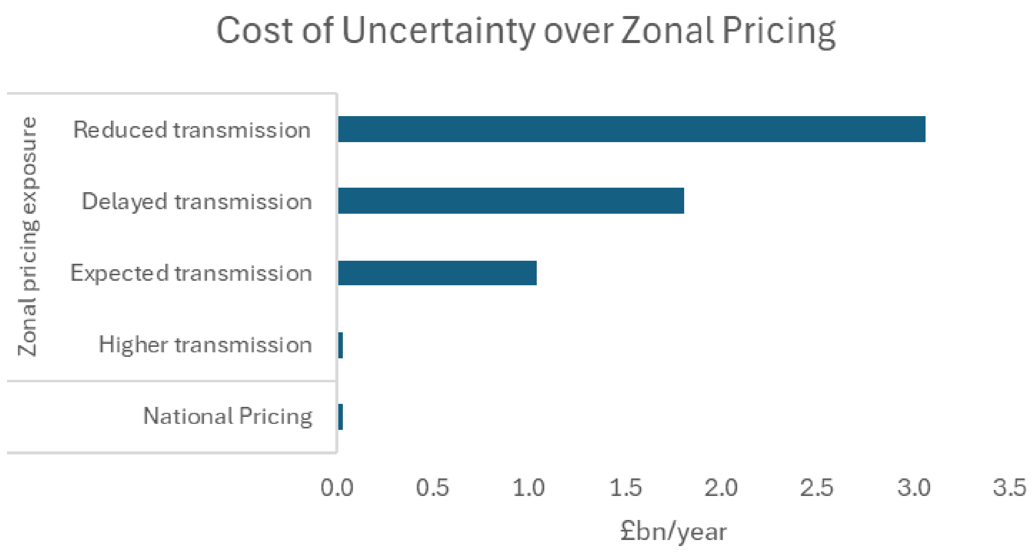

Figure 2. *Effect on total costs*

These elevated strike prices will directly affect consumers, potentially increasing costs by up to £3 billion annually. This substantial cost increase represents the total additional investment expense depending on investors' risk perception, which will ultimately be passed through to consumers. Some analyses[22,23] postulate that zonal pricing will allow producer surplus to be redistributed to consumers. Our analysis is unable to assess the potential for producer surplus, but we note that the increased risks in some zones described above are likely to increase CfD clearing prices across *all* zones. Unless CfD prices are set within zones rather than GB-wide (see below) zonal pricing creates a new source of potential producer surplus that impacts consumer bills.

Finding 3: Future Risk Reduction

Zonal pricing risks should diminish over time as transmission infrastructure development becomes more certain. If implemented at a later stage, investors could incorporate locational risks into their investment decisions with greater confidence once transmission uncertainty decreases. However, for the present, the variation between our modelled transmission scenarios represents a significant risk that investors would face under near-term zonal pricing implementation.

This suggests that since transmission functions as a price-maker rather than a price-taker in zonal markets, zonal pricing would ideally only be introduced after resolving key uncertainties regarding major infrastructure developments. Early implementation risks "putting the cart before the horse," exposing investors to unnecessary risks potentially reaching £3 billion annually, which could negate many of the financial benefits that zonal pricing might otherwise deliver.

3. Migrating Generation South – What Would ‘Plan B’ Entail?

Moving South – analytical basis

The analysis above concentrates on the risks associated with moving to zonal pricing whilst simultaneously trying to build out around 11GW of new transmission capacity and around 20 GW of new on/offshore wind in Scotland/Northern England by 2030. This raises the question of whether it might be possible to put at least some of that generation somewhere else entirely. Indeed, relocating generation to less constrained locations is identified as a benefit in some zonal pricing analyses.[24]

This part explores the proposition that locational pricing and/or delayed transmission investment would deter investment in constrained regions, so if the 2030 target is to be met more renewable generation capacity would be needed closer to the main demand centres in southern GB.

To investigate the potential changes in renewable generation capacity location and mix, we employed an energy balance model of the GB electricity system. The model balances electricity generation with demand on an hourly basis for a representative year. Our starting conditions are calibrated to the 'Further Flex and Renewables' (FFR) scenario for 2030 from the NESO CP30 report.[25]

The model dispatches generation hourly in merit order, beginning with variable renewables (offshore and onshore wind and solar), followed by nuclear, hydro, CHP, seasonal storage, interconnectors, short-duration storage (batteries), low carbon dispatchable generation, and unabated gas-fired generation. Hourly wind speed data is aggregated to represent blended values for different regions.

We conducted three experiments, each reducing new off/onshore wind capacity in northern GB while increasing new onshore wind and solar capacity in southern GB. Onshore technologies were selected because they could, in principle, be deployed at the scale and speed necessary to continue to meet the 2030 Clean Power Target. We assume that the timeline for identifying and developing new offshore sites would likely be longer, and in any case could give rise to further transmission constraints. The overall effect rebalances some of the CP30 capacity additions from northern to southern GB.

- **Experiment 1:** Adds sufficient new southern renewable capacity to match total renewable generation output calibrated to match NESO 2030.
- **Experiment 2:** Adds sufficient new southern renewable capacity to meet the CP30 emissions target, with onshore wind capacity additions predominating.
- **Experiment 3:** Follows Experiment 2 but maintains equal additions of onshore wind and solar capacity, and adds sufficient additional battery storage to allow solar to make the same contribution to energy balance as in CP30 FFR.

In each experiment, reductions in new northern wind capacity increase step-wise up to 15GW in our main case. We also examine the impact of reducing new northern wind capacity by up to 20GW to explore more pronounced responses to locational pricing and/or lack of new transmission capacity.

Moving South Main Findings

In this section, we report outcomes relative to UKERC analysis calibrated to match NESO's FFR 2030 scenario, showing the implications of progressively reducing wind capacity additions in Scotland and Northern England.

Experiment 1: **Keeping annual VRE generation constant, with wind-dominated southern capacity additions**

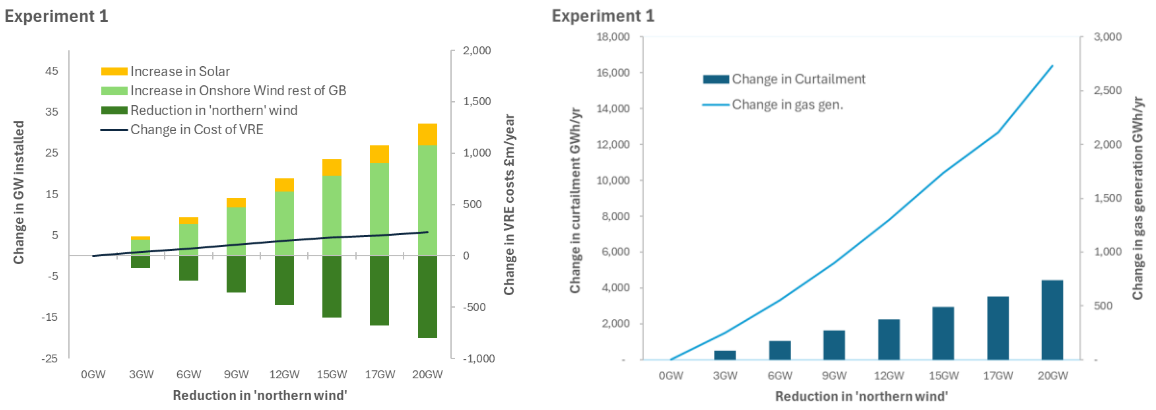

Figure 3. *Experiment 1 effect on capacity requirements, costs, curtailment and gas generation*

Key points:

- Total renewable energy capacity increases. The impacts on annualised costs of variable renewables and imported electricity volumes are minimal.
- The higher installed capacity operating at lower load factor and poorer correlation with demand means that curtailed variable renewable output increases[iv] while exported electricity volumes decrease.
- **The CP30 CO_2 target is not achieved** because unabated gas-fired generation must increase to maintain system reliability. This is driven by the poorer correlation of southern renewables with the GB demand profile.

[iv] While higher installed capacity at lower load factors can result in the same annual TWh of renewables availability, curtailment increases because peak generation is higher. This increases the scale of mismatch between supply and demand in hours when the renewable output is in surplus.

Experiment 2: Keeping unabated gas-fired generation constant, with wind-dominated capacity additions

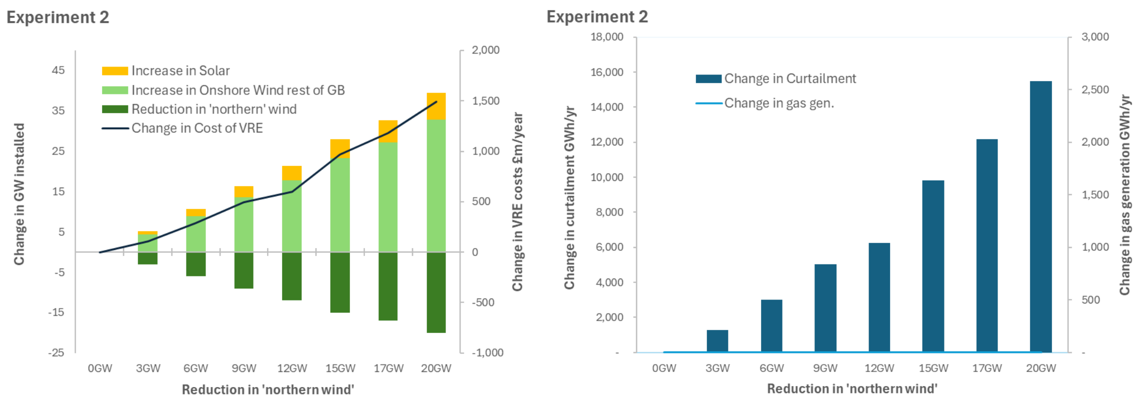

Figure 4. *Experiment 2 effect on capacity requirements, costs, curtailment and gas generation*

Key points:

- The CP30 CO_2 target is met because unabated gas-fired generation is kept below the 5% of total generation aspiration. This requires considerably more variable renewable capacity compared to Experiment 1.
- Imported electricity volumes remain largely unchanged, while exported volumes increase.
- As with experiment 1, a higher capacity operating at lower load factor mean that **annualised generation costs and curtailed variable renewable output increase** significantly – by up to £2.5bn per year.

Experiment 3: Keeping unabated gas-fired generation constant, with equal wind and solar capacity additions

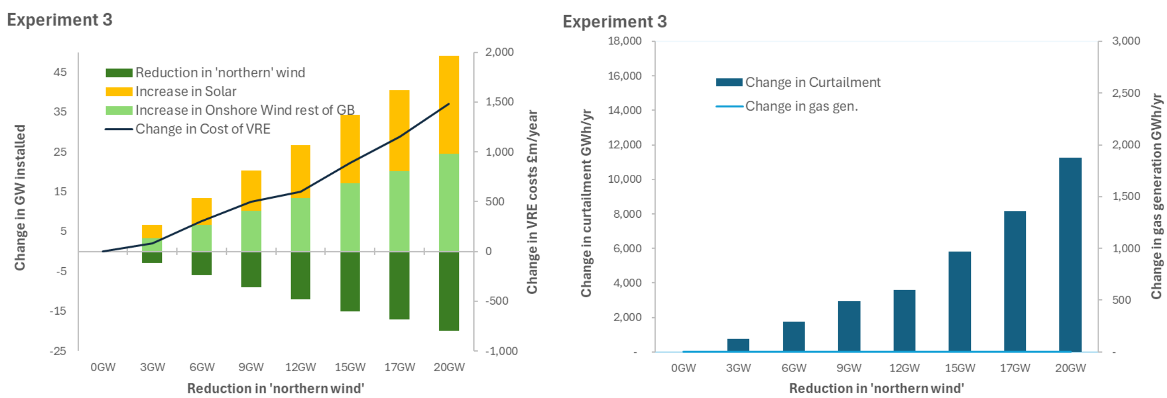

Figure 5. *Experiment 3 effect on capacity requirements, costs, curtailment and gas generation*

Key points:

- As with Experiment 2, the CP30 CO_2 target is met.

- Imported electricity volumes remain largely unchanged. Exported volumes increase, relative to the starting conditions, and are higher than in Experiment 2.
- Annualised costs increases are similar to Experiment 2. Curtailed variable renewable output increases significantly relative to NESO FFR, but by less than in Experiment 2.

Moving South Increases Renewable Capacity Needs, Costs, and Curtailment

The analysis reveals that substantial additional onshore wind and solar power capacity would be required if more variable renewable capacity is located in southern GB. Simply replacing the "lost" output from the new northern variable renewable capacity with an equivalent amount of southern variable renewable output is insufficient to meet CP30 clean power system objectives. This stems from several factors: i) the weaker correlation of southern renewables with the GB demand profile, ii) the generally higher load factors of offshore wind compared to onshore wind, and iii) the superior load factors of northern offshore and onshore wind compared to the rest of GB.[v] This means that the total level of generation that cannot be absorbed GB-wide goes up, even though transmission constraints may be reduced: curtailed energy volumes *increase* by 5.8 – 15.5 TWh/year.

A summary is provided in Figure 6 below.

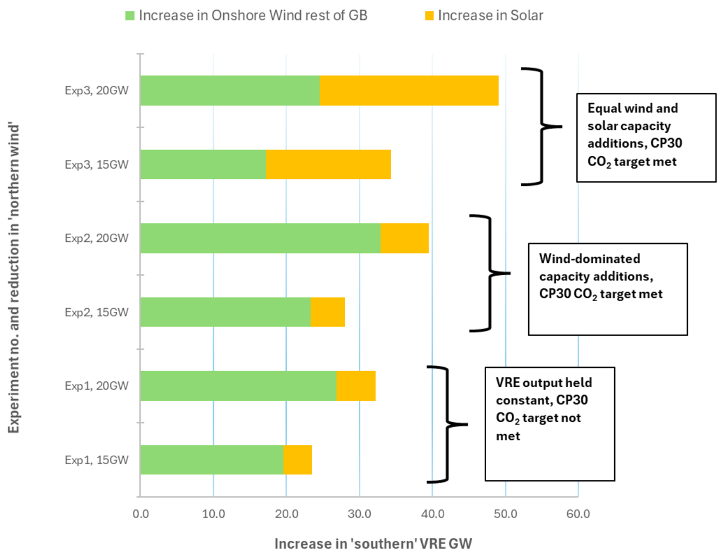

Figure 6. *Summary of effect on capacity requirements across the three experiments*

[v] Our analysis aggregates wind speed data from sites across England and Wales. This may even overstate generation output in England, noting the higher wind resource but more limited site availability in Wales, and potential for much lower load factors in locations in Southern England where wind farms are currently largely absent. Further analysis could test sensitivity to load factor data.

The analysis indicates that replacing 15 to 20 GW of northern GB wind creates a need for 17 - 33GW of additional onshore wind and 5 - 25GW of additional solar capacity. This translates to approximately 400-800 additional wind farms and 100-500 additional solar farms, based on current typical sizes for new large-scale farms.[26,27] This would be in addition to the 4GW of new onshore wind and 32GW of new solar in the rest of GB already envisaged in the CP30 FFR scenario. In total, including the CP30 FFR scenario, our experiments demonstrate that meeting CP2030 goals with less new Scottish/Northern England wind energy would require a combination of **five to nine times more onshore wind and large-scale solar generation** in England and Wales compared to current installed capacity.

We do not take a view on whether this scale of expansion is plausible in terms of available sites, planning, or distribution network capacity. However, it illustrates the challenge entailed in a 'plan-B' scenario where generation moves away from Scotland and Northern England in response to zonal pricing and transmission constraints.

4. Economic Curtailment – a Fundamental Feature of High Renewables Systems

Wind and solar generation inherently lack flexibility, producing power only when weather conditions permit. Nevertheless, it is possible to create reliable electricity systems primarily powered by renewables by complementing them with various flexibility mechanisms. These include investments in electricity storage technologies (such as batteries and hydrogen storage), demand flexibility enhancements, and improved import-export capabilities with neighbouring countries.

However, economic constraints limit the extent to which such flexibility investments are cost-effective. Consequently, in an economically optimised electricity system using current technologies, some variability from wind and solar generation will likely remain unbalanced, and surplus electricity will be 'spilled', meaning renewable generators curtail. Spillage typically occurs when electricity's marginal value is low, during prolonged high variable renewable generation periods, low demand periods, or when existing storage capacity is fully utilised. In line with other analyses[28], our research shows this is true GB-wide as well as within constrained zones. Indeed, we find that moving wind and solar out of constrained zones, expanding onshore wind and solar such that CP2030 targets are met, would *increase* GB-wide curtailment.

Energy spillage does not necessarily constitute an economic or technical problem. Some degree of spillage may be economically optimal when the cost of additional equipment needed to capture excess energy exceeds the value of the energy itself. Generally, optimal spillage levels increase when generation costs are low (due to abundant renewable resources) and/or flexibility mechanisms are expensive.

The current arrangements combine CfDs where renewable generators receive fixed payments for their output, with firm access rights, meaning that generators are compensated if energy is curtailed. This arrangement means consumers pay above wholesale market value during periods of low electricity prices but pay less during high-price periods. Overall, CfDs are designed to reduce consumer costs by lowering investment risks and capital costs for developers.

The interaction between zonal pricing and CfDs in the presence of uncertain and/or limited transmission upgrades would change the terms of the arrangements. The strike price in CfD auctions is determined by developers spreading total project lifetime costs across anticipated sales hours. If policy changes reduce sellable hours, developers will proportionally increase auction bids to maintain commercial viability. Moving to zonal pricing could reduce constraint payments to renewable generators, but if it also results in higher GB-wide CfD prices this will not reduce overall consumer costs.

Our findings diverge from some other analyses in the field. Other studies acknowledge that transmission capacity uncertainty significantly impacts renewable generators' sales volumes during constrained periods, but they draw different conclusions about the economic consequences. Rather than factoring this risk into renewable energy delivery costs as we have done, alternative analyses suggest that under zonal pricing sales volume reductions from transmission constraints would translate to consumer savings. We consider this assumption flawed, as it presumes investors would maintain their original investment plans despite these risks.

This is why we have explored both the impact on prospective CfD prices and the scale of expansion needed in less constrained locations to hit the 2030 clean power goal. It is beyond the scope of this paper to examine whether 'plan-B' – a five to ninefold increase in onshore wind and solar in England and Wales – is feasible. Some of it might be, but if we retain the assumption that expanding on/offshore wind in Northern England and Scotland is the most plausible route to 2030 goals then zonal pricing induced volume risk in forthcoming CfD auctions remains a key policy challenge.

Our analysis has deliberately limited scope to the potential impact of zonal pricing on forthcoming CfD auctions, and hence costs of meeting the government's 2030 target. A wider set of options is still under review as part of REMA, including changes to the fundamentals of CfD arrangements. One option is to make CfDs 'deemed' or 'capacity-based'. Doing so would disconnect CfD revenues from electricity output (in full or in part) and could alleviate volume risk. An alternative (or additional action) is to move CfD prices to regional rather than a GB-wide basis, which could reduce the likelihood of volume risk in constrained zones driving up CfD prices across Great Britain.

Substantial CfD reform is not possible in time for AR7 and possibly all CP2030 relevant CfD auctions. This demonstrates how different dimensions of REMA interact, and how the fundamental issues that REMA is rightly grappling with need to be tackled together.

5. Policy Implications

Surprisingly, the impact of volume risk on CfD prices does not appear to be given much attention in most analyses of the benefits of zonal pricing, at least until very recently.[29] Instead, it appears that some analyses simply count the reduction in constraint payments that stem from prices clearing within local zones rather than national markets as a saving that can be passed through to consumers. Under zonal pricing, there arguably could/should be some reduction in constraints over time in response to the new price signals (e.g. new demand, new sources of flex etc.) and we note the possibility that developers may be able to mitigate some of the risks directly. Our concern is that this effect is too uncertain for investors to rely on in advance of AR7-9, and they will simply factor the full amount of volume risk into their prices. Since CfD locks in prices at the beginning of the contract, these premiums get baked-in for the duration of the CfD term, and there's no room for learning.

Zonal markets offer efficiency gains relative to the current status quo, for example in reducing payments to gas generators required to 'turn up' by the System Operator to replace constrained generation under national pricing. They would also be likely to dispatch interconnectors more efficiently. Options to enhance locational signals under national pricing also exist[30]. However, the fundamental dynamic where reduced/more uncertain sales volumes in constrained zones feed through into increased CfD prices appears to us to be an inevitable consequence of moving to zonal prices. This is particularly problematic now, when uncertainties are highest. The propositions is to introduce zonal pricing whilst trying to simultaneously deliver unprecedented expansion in capacity of renewable generation in parallel with build out of new transmission lines, timelines for all of which are inevitably uncertain.

Assuming no substantial changes to CfD designs, if Government wishes to avoid the risk of negative impacts on forthcoming Allocation Rounds, the only feasible alternative to ruling out zonal pricing until conditions change would be to undertake to fully recompense prospective bidders for volume risk. This approach was advocated by the Energy Systems Catapult in a report published in October 2024.[31] However, there are no clear plans to mitigate volume risk in the most recent report on REMA.[32] Whether measures to protect against volume risk would be practical, and adequate to reassure prospective investors given the short time between any decision on zonal pricing and AR7 remains to be seen. There has to be a risk that investors would price risks into CfD bids regardless, and yet still be eligible for volume risk compensation – the worst of all worlds.

Concluding Questions

Despite extensive consultations and analysis REMA has yet to conclude. As a result, we now find ourselves in a situation where uncertainty over REMA risks failure of the CP30 mission, because the debate over locational pricing is overshadowing forthcoming allocations of CfDs that will be essential if the CP30 goal is to be achieved.

Since policy choices around zonal pricing are now extremely urgent, we propose the following questions for policymakers:

1. Is there appetite for the risk of a material increase in CfD prices for AR7-9 relative to a counterfactual where zonal pricing is not introduced?
2. Is a 'plan-B' feasible, such that the 2030 Clean Power Target can still be met, should some investors either decline to participate in AR7-9, or if bid-prices turn out to be unacceptably high as zonal volume risks feed through into CfD prices?
3. Is it possible to provide investors with enough information to allow them to develop an informed view of the impact of zonal pricing in time for AR7-9? This might include location and number of zones, rules for trading across zones, market clearing arrangements during periods of oversupply, and any arrangements in place to protect forthcoming and legacy investments.
4. Is it feasible to fully protect AR7-9 investors from the uncertainties created by moving to zonal pricing ahead of build-out of new transmission capacity, to avoid them pricing this risk into their bids, including any measures to protect them from the volume risk that this would entail?
5. How substantial and certain is the 'size of the prize' associated with moving to zonal pricing now (rather than some later date), such that the short-term costs associated with doing so are outweighed by the benefits that could accrue in the mid-2030s and beyond? And related to this, whether a package of incremental reforms could deliver the operational efficiencies that zonal pricing provides long-term with fewer negative effects on the CP2030 target.

Our analysis is deliberately focused on the risks that stem from introducing zonal pricing ahead of major transmission and generation capacity build-out needed for the 2030 target, with all the risk and uncertainty concomitant with such a bold endeavour. We do not dispute the potential for zonal pricing to yield operational efficiencies in theory, or in the longer-term. We also do not consider wider factors, including Parliamentary time for new legislation, distributional impacts on households, or implications for industrial competitiveness around the UK. In many cases trade-offs must be deliberated, which is why the decision over zonal pricing is difficult. However, unlike the interactions with forthcoming CfD auctions, few of these are time critical. The most immediate question for policymakers is not whether zonal pricing is a good idea in principle but whether now is the right time to implement it.

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