Locational signals in a reformed national market

A review of options

UKERC Working Paper

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Executive Summary[1]

In December 2024 the UK Government published its *Clean Power 2030 Action Plan*. This ambitious document sets out the actions needed to ensure 95% of Great Britain's electricity comes from clean energy in only six years. Alongside the Action Plan the Government published an 'Autumn Update' to the Review of Energy Market Arrangements (REMA), ongoing since 2022. The Autumn Update provides important new information across multiple aspects of the REMA decision-making process. It emphasises that "no decision has yet been taken between zonal pricing or reformed national pricing" – which has become the most hotly contested aspect of the REMA programme. This report explores a wide set of options that could enhance locational signals to market participants in a reformed GB-wide wholesale energy market.

Our report aims to inform the UK Government's upcoming decisions but not to determine whether a reformed national market or a move to zonal pricing are most appropriate in the long term. Instead, it starts with two observations. The first is that a good decision requires a well-articulated vision of what each option would look like in practice. This needs to factor in both price *and volume* risks, viewed from the perspective of market participants. The second is that zonal pricing will take several years to introduce, so there is value in introducing incremental reforms to current market arrangements that can improve locational signals for investment and operation in the meantime. This second point is important: improving signals within a national market is the only option to better manage system limits through to the early 2030s.

REMA considers a range of options beyond the wholesale electricity market, most notably changes to the design of the capacity market, contract for differences (CfDs) for renewable generation, and the way the costs of the transmission network are recovered. However, in considering the options for a reformed national market, the latest iteration of REMA focuses only on transmission network charges and balancing arrangements. It pays little attention to the potential for the wider set of regulatory arrangements, secondary or ancillary markets, or other factors that may deliver locational signals relevant to market participants.

To reach a good decision on how to reform locational signals in the electricity system, it is important not to neglect important interactions between different aspects of the commercial and regulatory landscape and to take a sufficiently broad and comprehensive approach. Many of the options discussed in this report lie outside the wholesale energy market *per se.* However*,* market participants respond to regulatory rules, markets, policy incentives, and wider project considerations *in the round.* Taken together, these determine the value stack that different market participants can access, and what risks they face in doing so. This report therefore considers all the prospective changes that could be made to the regulatory, market and incentive

[1] This report was completed ahead of the publication of UK Government's REMA Autumn update, published in December 2024. It does not include that update in its review of the national debate on REMA and it does not respond to or reflect in detail the minded to decision in that document.

structures that bear upon market participants' decisions about where to locate, and how to operate. Whilst there is a large literature on each of the various regulations, interventions and incentives we discuss below, there has been very little attention to how they individually and collectively affect locational investment and operational decisions. This report therefore seeks to fill a gap, by discussing a wide array of rules, incentives and procedures with a locational lens.

How to think about locational signals

Locational signals are diverse, both in terms of where they come from and in the form they take. They include both: incentives on market participants to align their dispatch with system limits; and rules that limit or require operation based on location. Changes to incentives, rules, markets and mechanisms need to take account of different sources of risk – volume as well as price risks – and to consider both initial market dispatch and the actions taken by the system operator to redispatch the system.

The following overarching points emerge from our analysis of the factors affecting locational decisions reviewed in this report:

Locational signals cannot be neatly divided into those that affect only operation and those that affect only investment. Rather each timescale affects the other. For example, operational-timescale signals can only help dispatch assets that already exist, therefore the fleet of assets capable of responding to operational signals is defined by investment timescale signals. Conversely, some assets, particularly those like batteries that don't rely on explicit investment support mechanisms, will build an investment case largely from the aggregate revenues, and risks thereof, from operational timescale signals across the asset's life.

Improved locational rules and mechanisms can give the National Energy System Operator (NESO)improved ability to support effective dispatch and redispatch. This includes making improvements to the balancing mechanism, moving gate closure to allow greater time for NESO to use the balancing mechanism effectively, and the introduction of pre-gate closure constraint management markets. It could also include giving NESO a formal role in dispatching the market, for example through a move to a more centralised dispatch[2].

Locational incentives on market participants to align their dispatch with system limits are possible but can introduce significant risk and uncertainty, which can affect the investment case. Whilst incentives may be cost reflective in theory, to be so in practice, market participants need to forecast those signals sufficiently in advance and be capable of responding to them. In many cases, on operational timescales, this is not practically possible.

There are significant locational signals beyond the electricity system's commercial and regulatory framework. These are out of scope for REMA. But

[2] The REMA Autumn Update, published in December 2024, indicated that DESNZ are note minded to use centrale dispatch due to concerns over deliverability, investor confidence and value for money.

they mustn't be ignored. These include the strength of renewable resources, geographical considerations such as seabed depth for offshore wind farms, and planning and consenting rules different aspects of which are under the control of national, devolved or local government.

Strategic spatial planning has a profound impact on location decisions, and it is essential to consider how other locational signals will work with the plan. The Strategic Spatial Energy Plan will have a profound impact on the geographical distribution of the electricity system. If the plan is to be delivered, it is important that the overall set of commercial and regulatory arrangements fits together to ensure that the assets identified as being needed in different locations are delivered in the timescales, volumes and places required by the plan. For example, if TNUoS charges for generators are higher in locations favoured by the plan for generation capacity, then consideration will have to be given to how incentives for those generators are provided, so they are not deterred from operating in those locations.

It is important to distinguish between cost reductions through more efficient system operation and a transfer of costs to other cashflows where they are less transparent and could even increase overall costs. For example, removing constraint payments could result in higher CfD strike prices, with increases reflecting both the *expected* reduction in revenue and an additional *risk premium* associated with the difficulty in forecasting future constraints.

Revisit the merits of locationally differentiated CfD and capacity mechanism auctions, and introduce locational dimensions to ancillary/system service contracts. The second REMA consultation partly ruled out some options, such as locational elements in future CfD auctions and capacity market contracts, but this report suggests that these options offer considerable scope to improve locational signals for both renewable generators and providers of flexibility.

Interconnectors are a special case and aligning their operation with system needs could reduce costs. It is possible to develop improved arrangements for redispatching interconnectors, but this needs NESO to work proactively with connected system operators. For example, Danish and German Transmission System Operators collaborate on an intraday cross-border redispatch mechanism which manages significant volumes. GB interconnectors are unusual in that they are treated as GB market participants, whereas cross-border capacity between most EU countries are treated as regulated network assets. There may be value in reviewing the status of interconnectors and how they receive revenue in our market.

Reform options

The report reviews a wide range of reform options that could be implemented alongside a nationally priced market. The options include signals that would provide incentives for market participants to invest in particular places or operate in location-specific ways. They also include rules and mechanisms which allow NESO to take more control of either the initial market dispatch, or the redispatch processes required to align operation with system limits.

Reflecting the need for reform to look right across the electricity system's commercial and regulatory framework, the reforms include consideration of regulated charges such as transmission network use of system charges (TNUoS), and adaptation of system services such as response and reserve, technical ancillary services, the capacity market and policy support schemes.

Figure ES1 groups the different options that we have considered and Tables ES1 to ES5 summarises our conclusions. The report does not attempt to rule specific options in or out; rather, it provides a considered view on the value of exploring each further. Some, such as improvements to NESO's IT and control room processes are extremely likely to be valuable and are, at least to some extent, already in train. Others, such as dynamic locational Balancing System Use of System Services (BSUoS), are, whilst useful in theory, unlikely to be practically viable.

Group 1: Interventions to incentivise market participants to align wholesale energy market dispatch with network limits

Locational BSUoS charges on generators and consumers with settlement-period granularity	Reform generation TNUoS	Remove the cap at zero for demand TNUoS charges and change the basis for demand charges	Introduce locational signals from other cash flows to incentivise energy market dispatch

Group 2: Mechanisms for NESO to better organise market dispatch and re-dispatch

Introduce pay-as-clear locational prices for Balancing Mechanism actions	Introduce a pre-gate closure constraint management market	Non-firm access rights	Central dispatch

Group 3: Mechanisms for the locational procurement and dispatch of non-energy services

Locational signals through capacity market: (a) locational minima / maxima (b) locational prices	Introduce (a) locational minima / maxima and (b) locational strike prices in the CfD auctions	Introduce a locational element to frequency response and reserve markets	Better coordination of tendering across technical ancillary services and restoration

Group 4: Changes to market structures and processes

Move gate closure further ahead of real time	Improve NESO IT and control room processes	Introduce Dynamic Locational Transmission Loss Factors with settlement-period granularity

Group 5: Interconnector specific interventions

Expose interconnectors to a locational shadow price	Develop new SO-SO frameworks for pre-gate closure trading

Figure ES1: Summary of options considered in the report

Table ES1: Summary of conclusions from the review of interventions based on incentivising market participants to align wholesale energy market dispatch with network limits (Group 1)

Intervention	Conclusion
Locational BSUoS charges on generators and consumers with settlement-period granularity	For the reasons identified by the two recent BSUoS taskforces (primarily: major practical challenges to cost-reflective BSUoS delivering a useful signal) there does not appear to be value in taking this forward.
Reform generation TNUoS	Generation TNUoS is primarily an investment-timescale locational signal and is likely to stay that way. As noted in Ofgem's recent open letter on strategic transmission charging, it currently has high levels of locational differential and uncertainty in future charges. Ofgem has recently argued that these work against delivery of net zero and has suggested a temporary cap and floor to deal with them in the short term in their current form. There is a risk that future TNUoS based on the current methodology (based on the long run marginal cost of investment in the transmission network) will be mis-aligned with a strategic plan for some technologies, particularly renewables and storage, where it creates high charges in areas where a Strategic Spatial Energy Plan (SSEP) requires investment. A full review of the principles on which TNUoS is based should be conducted alongside proposals for how an SSEP would be implemented (e.g. cost reflective vs cost recovery; reflective of the cost of what?)
Remove the cap at zero for demand TNUoS charges and change the basis for demand charges	There could be significant value in removing the floor at zero for demand TNUoS and realigning the basis on which demand is charged locational TNUoS. This would better reflect the impact that demand has on transmission investment in areas which are generation dominated. Although Ofgem has expressed a view that neither generator nor demand TNUoS should be used for operational signals, this report suggested there may be value in exploring the possibility of delivering improved locational operational signals through demand-side flexibility.

Intervention	Conclusion
Introduce locational signals from other cash flows to incentivise energy market dispatch (e.g. capacity market, CfDs, Transmission Loss factors)	This is unlikely to deliver suitable operational signals: most cash flows are primarily investment- rather than operational-timescale, and except for BSUoS and TNUoS (discussed separately), don't directly reflect market participants' contribution to locational issues such as transmission constraints. Therefore, any alignment is coincidental rather than cost-reflective and could change as the cost drivers and cash flows are inherently uncoordinated. The most promising approach would be to adapt dynamic, locational transmission loss factors which are currently likely to show correlation with transmission constraints. However, they would be difficult for market participants to forecast and are likely to suffer many of the same difficulties as BSUoS reform.

Table ES2: Summary of conclusions from the review of interventions based on providing better tools for NESO to organise market dispatch and redispatch (Group 2)

Intervention	Conclusion
Introduce pay-as-clear locational prices for balancing mechanism actions	There is value in investigating this as a way to deliver stronger locational signals to market participants in redispatch, allowing easier forecasting and assessment of likely balancing mechanism revenue streams and allowing assets to build business cases to locate in places favourable to the system and actions taken at or after gate closure to balance it.
Introduce a pre-gate closure constraint management market	Has the potential to provide an important new tool for NESO capable of supporting better outcomes for the technical and financial aspects of redispatch. If market participants can forecast future NESO actions through constraint management markets, or the extent to which the market might offer long-term contracts, the reform also has the potential to inform locational investment in flexible assets located in places favourable to the system.
Non-firm access rights	Reductions in the cost of operating the system might be expected through removal of the entitlement to compensation for denial of access which is associated with firm access rights. However, such changes would also change network users' expected revenues and introduce uncertainty, with a potential impact on those users' other costs. Those costs would need to be recovered and risks hedged via some other means if they are to continue to use the network. There is most likely to be value in exploring non-firm

Intervention	Conclusion
	access rights for two-way energy storage assets as an approach to maximise the connection of flexibility without unduly limiting network access for other assets.
Central dispatch	Has the potential to deliver a system dispatch which better aligns both with system and network limits from the day-ahead stage onwards, helping to reduce the volume of redispatch significantly and utilise the fleet of assets more optimally. The utilisation of individual assets may differ from the way existing owners optimise their positions under current decentralised arrangements as the central dispatch aims to optimise against system-wide objectives rather than optimising each asset individually. However, there is some risk that the central dispatch algorithm isn't fully capable of optimising the operation of individual assets and the wider system; the impact on network users' revenues will depend primarily on access rights.

Table ES3: Summary of conclusions from the review of interventions based on providing mechanisms for the locational procurement and dispatch of non-energy services (Group 3)

Intervention	Conclusion
Locational signals through capacity market: (a) locational minima / maxima (b) locational prices	Despite the second REMA consultation's position not to introduce locational capacity market signals "as a standalone option", we think there is value in exploring them further, considering the locational need for assets capable of delivering on future definitions of 'stress events' (including multiple types of event over longer and shorter timescales). The capacity market at present procures simply capacity. An ability to deal with stress events in a system with a significant capacity of variable renewables should also entail procurement of sufficient energy. However, an ability to access the energy depends on there being sufficient network capacity. A reformed, locationally aware capacity market could ensure energy resources are placed where there already is, or is expected to be, enough network capacity or it can be aligned with further network expansion and wider strategic infrastructure planning through the SSEP.
Introduce (a) locational minima /	Despite the second REMA consultation's position not to take forward the introduction of locational CfD auction signals as a "primary option", this report concludes that there is value in

Intervention	Conclusion
maxima and (b) locational strike prices in the CfD auctions	exploring further, either to support delivery of a locational SSEP or to reflect the value of a geographically diverse fleet. As in the case of capacity market reforms, locationally aware CfD auctions could be aligned with the needs of an SSEP, ensuring new capacity is built where network capacity is, or is expected to be, available or it can be aligned with future network expansion. This would need to be delivered through coordination with future plans for seabed leasing.
Introduce a locational element to frequency response and reserve markets	There appears to be significant potential for some response and reserve capacity to be procured in areas where it cannot deliver the system-services required, e.g. where response ‘headroom’ is ‘sterilised’ behind a transmission constraint. Therefore, there would appear to be value in considering how to introduce locational considerations into the procurement and scheduling arrangements for response and reserve provision in the future.
Better coordination of tendering across technical ancillary services and restoration	Individual system services tend to have strong locational signals through zonal tendering rounds. However, improving the coordination and visibility of tenders over the coming years would allow assets to more easily combine contracts to build a business case where there is locational correlation between service needs.

Table ES4: Summary of conclusions from the review of interventions based on changing market structures and processes (Group 4)

Intervention	Conclusion
Move gate closure further ahead of real time	Providing more time to NESO for balancing mechanism-based redispatch following gate closure will relieve the technical challenge and may allow a lower-cost lower-carbon redispatch to be organised. The argument against this – that removing time for the intraday market to optimise the initial market dispatch would increase costs – appears unproven.
Improve NESO IT and control room processes	Improvements have been made, particularly regarding improved non-locational energy balance, through the introduction of the Open Balancing Platform. NESO should prioritise improvements to locational balancing, e.g. Bids and Offers to solve network constraints.

Introduce Dynamic Locational Transmission Loss Factors with settlement-period granularity	There are significant implementation challenges for dynamic TLFs and it is uncertain how effective the intervention would be. This would depend on the ease with which market participants would be able to forecast TLFs. The approach is likely to suffer similar challenges to those identified for dynamic, locational BSUoS.

Table ES5: Summary of conclusions from the review of interventions based on providing interconnector-specific interventions (Group 5)

Intervention	Conclusion
Expose interconnectors to a locational shadow price	Theoretically, this intervention can deliver a locational price signal to interconnectors whilst leaving other assets facing the national wholesale price. However, it is likely to face significant practical challenges, create significant barriers to market-participants trading across interconnectors, including regulatory risk arising from uncertainty over how such a system might be 'tweaked' in the future. It is likely to struggle to align with the Trade and Cooperation Agreement and European Internal Energy Market rules, as such, there may be limited value in developing the idea further.
Develop new SO-SO frameworks for pre-gate closure trading	There appears to be significant potential for the NESO to work proactively and cooperatively with connected System Operators to deliver a more transparent and predictable trading framework utilising (NE)SO to SO pathways (rather than the current NESO to market-participant pathway). There is an apparently successful example operating within European Internal Energy Market (IEM) rules between Germany and Denmark.

Conclusion

In summary, we believe that there is a strong case to consider the full range of factors that might provide opportunities to enhance locational signals. The regulatory, market and policy context as a whole is what affects market participants' risks and revenues, and hence investment and operational decisions. The feasibility and materiality of many options requires additional investigation, but the analysis presented in this report demonstrates that there is a strong case for undertaking this additional work. We are concerned that REMA has taken too narrow a view on what could be implemented as part of a reformed national market, and as the review moves through the next phase of assessment, the UK Government needs to broaden that perspective to ensure that the best possible reformed national market model is considered.

1 Introduction[3]

Locational signals are at the centre of the debate about how to reform the wholesale electricity market and the policy and regulatory framework that surrounds it. This has been fuelled by the growing cost of transmission constraints, argued by proponents of reform to be at least partly because of the lack of locational signals on investment in and operation of assets connected to the network. For example, kicking off the debate in 2021, National Grid ESO, now the National Energy System Operator (NESO), said “there is a need to incentivise assets to locate and dispatch where they can minimise whole system costs” and that “single GB market means generators and demand are equally likely to self-dispatch wherever they are in the country, ignoring the benefits or costs to the system. This increases constraint costs that are ultimately passed through to consumers.” [1]

A lack of locational signals means there is little incentive for market participants to align with transmission limits. The issue is exacerbated by what the National Energy System Operator (NESO) has admitted is “insufficient capability of legacy IT systems” for redispatching the market to bring final operation back within those limits [2]. The debate has been shaped by the UK Government’s Review of Electricity Market Arrangements (REMA) which aims to reform the market to better support delivery of a decarbonised electricity system.

Two broad sets of proposals have been offered in response to the challenge of limited locational signals. The first focuses on moving from a national wholesale market to locational wholesale pricing. That means the market price of electricity varies by location based on local supply and demand and local import and export constraints.

This introduces a locational price signal which incentivises all market participants – generation, demand, storage and interconnectors, any of which can provide flexibility – to align their operation with locational constraints. It also includes removal of firm access rights, which allows the market operator to prohibit operation of assets where this would contribute to breaching system limits. UK Government ruled out a move to nodal locational pricing in the second REMA consultation, but retained the option of zonal locational pricing.

The second category of reform proposals have been referred to as ‘alternatives to locational pricing’, or ‘reformed national market’, and are based around maintaining a nationally priced wholesale energy market but improving signals to allow either better optimisation of the initial market dispatch itself or to enhance the ability of NESO to redispatch assets to ensure operation aligns with system limits.

There has been extensive modelling of the first set of options, with multiple pieces of analysis using simulations of future GB scenarios based on nodal or zonal pricing

[3] This report was completed ahead of the publication of UK Government’s REMA Autumn update [92], published in December 2024. It does not include that update in its review of the national debate on REMA and it does not respond to or reflect in detail the minded to decision in that document.

models largely borrowed from jurisdictions which already use those pricing approaches. There has been less focus on the incremental reform options for providing locational signals that retain a national wholesale market. During 2024, several studies started to look qualitatively at some options at a high level.

This report has two objectives. Firstly, to discuss how we should think about location when designing our electricity market and the wider commercial and regulatory framework. And secondly, to provide, at a high level, a more comprehensive and systematic overview of the options which could form part of the incremental reform approach.

The work aims to inform the debate in two important ways. Firstly, as the UK Government prepares to make a final decision, it is critical that both approaches – and the various implementation options associated with each – are fully articulated in a level of detail that enables comparison and a clear understanding across stakeholders of what each would entail. Secondly, if the Government chooses to move to locational pricing, there will be a long gap between that decision being made and new arrangements being delivered. For example, those changes are likely to require primary legislation in the UK parliament, the development of brand-new institutions and frameworks, working practices and the procurement of complex new IT equipment. There will also be a need for detailed analysis, not just – as has already been carried out – of the high-level theoretical approaches, but also of the detail of real-world implementation. It will not be appropriate to wait for locational pricing to be implemented during this gap; rather, some solutions discussed here could be used in the interim. It seems not unreasonable to suppose that a complex set of reforms and practical developments could take upwards of 5 years to be completed. By that time, as NESO's Clean Power 2030 advice in October 2024 highlights, constraint costs could be between £1 billion and £4 billion in 2030 under scenarios which include sufficient network to deliver clean power [2]. This shows there is value in acting sooner.

It is also important to be clear what this report will not do. The work does not take a view on the long-term suitability of locational pricing in GB. It will not provide a quantitative analysis of the costs and benefits of particular reforms, beyond pointing to existing work and highlighting the scale of some of the relevant cash flows. And its conclusions will not recommend that particular options are ruled in or out. Rather, conclusions will focus on identifying where it appears there is most value in exploring further.

1.1 Terminology

Many of the terms used in the REMA debate can be ambiguous and are often used with different meanings. This includes terms as fundamental to the debate as 'locational signal' and 'market reform'. This section provides a brief discussion of key terms and defines how they are used in this report.

1.1.1 Dispatch and redispatch

The term dispatch is used in this report purely in relation to the outcome of the wholesale energy market itself. The term redispatch means actions taken by the system operator, the National Energy System Operator (NESO), to adjust the outcome of the market.

Even with this definition, there can be some ambiguity when mechanisms within the wholesale market operate at different timescales (e.g. intraday market auctions adjusting a day-ahead dispatch) or when NESO takes actions before gate closure to pre-emptively adjust what it expects the final market dispatch to be. This report uses the term redispatch for any action carried out by NESO in order to adjust the final market dispatch because of a concern that system limits – locational or not – will be breached and includes actions taken either before or after gate closure. The difference between dispatch and redispatch is explored further in Box 1, below.

1.1.2 Locational signals

In this report 'locational signals' can mean both an incentive, rule or mechanism that, based on location, can affect a developer's decision on where to site an asset or service, or the owner's or system operator's decision on when or how to use it, i.e. it covered investment, dispatch, and redispatch.

- An incentive is a signal which asset developers or operators will consider as part of any overall business case or operating decision but one that doesn't create an absolute requirement to act. Commercial decisions made by market participants will consider locational incentives, but will usually need to balance many considerations, including both locational and non-locational incentives and other factors. An example of an incentive is a price signal which discourages but does not prohibit operation of, for example, a generator, at a particular time and location.
- A rule is a requirement or a prohibition to act in a particular way. For example, the Transmission Constraint Licence Condition (TCLC) is a rule which prohibits generators from acting in a way that seeks to obtain excessive benefit from reducing generation in response to a transmission network constraint. Breaching a rule tends to be associated with a penalty.
- A mechanism is simply a collection of rules and/ or incentives which can have one or more objectives as a whole. The most obvious example in today's market is the Balancing Mechanism (BM) which provides price incentives to encourage market participants to offer flexibility, and rules which define how both market participants and NESO are allowed to act to ensure that the system redispatch to align with system limits. A reform option that introduces a mechanism would be the introduction of central dispatch and which would provide a set of incentives to market participants about initial market dispatch and rules which would allow NESO to allow or prohibit the operation of particular assets.

Incentives are not the only way in which locational signals can be expressed and it is important that the market reform debate considers how rules and combinations of rules / incentives can be important.

Box 1: Dispatch and redispatch

The terms dispatch and redispatch describe two different processes within the electricity system.

- The term market **dispatch** relates to how the energy market itself sets the operation of assets based on the trading of electrical energy. With limited locational operational signals, if the energy market works effectively, it is likely to dispatch broadly in line with the national merit order, although it will also be influenced by other factors such as unit commitment constraints e.g. ramp rates and minimum stable operating levels. Under locational pricing, the market would dispatch assets with at least some consideration of locational limits.

- The term **redispatch** relates to how a system operator – in Britain's case, NESO – can adjust the market dispatch. The clearest example is through the Balancing Mechanism (BM). Following the end of market trading ('gate closure'), NESO uses the BM to change the dispatch – to ***re***dispatch – assets. This can be to correct misalignments in the initial market dispatch, such as national imbalances between generation and demand (where the latter includes network losses). It is also the process used to align operation with transmission limits and other system constraints. Redispatch can also include pre-gate closure options. Today NESO uses its own market trading to undertake some pre-gate closure redispatch where there is a high certainty of what the market dispatch will be at gate closure (and hence what locational constraints are likely to need reducing) and where trading options are likely to be cheaper than waiting for BM alternatives.

1.1.3 The electricity system commercial and regulatory framework

The term REMA implies a focus on markets. However, many of the options for introducing locational signals come from related non-market frameworks. Transmission Network Use of System (TNUoS) charges, transmission loss factors, Contract for Difference (CfD) cash flows for low carbon generation and the Balancing Mechanism all represent frameworks that work alongside the wholesale energy market itself. This report argues (see section 2.1) that the scope of reform should explicitly consider the full range of incentives, rules and mechanisms which collectively form the framework for market participants in the electricity system to operate.

To maintain that broader focus, we do not talk about reform of electricity markets, or market reform, but reform of the electricity system commercial and regulatory framework. This includes the wholesale energy market, other related markets such as the capacity market, along with various regulatory and policy frameworks including transmission charging, balancing, ancillary service arrangements and support mechanisms.

1.2 Structure of this report

The report is presented in four sections. This section provides an introduction to the project and an overview of the GB reform debate as it pertains to locational signals.

Section two is a discussion of how locational signals should be considered, providing a typology of locational signals and the different sources from which they emerge. It recommends ‘how’ locational signals should be considered in market design.

Section three lists the full range of cash flows and locational signals within the electricity system commercial and regulatory framework in Britain today, followed by a systematic discussion of key reforms that could be implemented alongside a national wholesale market. The report presents a conclusion commenting on each reform option, reflecting the potential value in exploring it further. However, it does not attempt to rule options in or out.

Finally, section four draws together the discussion on individual reform options to provide some high-level conclusions on what UK Government and the sector should do next.

1.3 The locational debate

1.3.1 Scope and timescales

The current debate about electricity market reform, or as we are referring to it, reform of the electricity system commercial and regulatory framework, has been running since 2021. NESO’s[4] first publication in their market reform process was in November 2021 [1]. This predated the formal start of the UK Government’s Review of Electricity Markets (REMA) process, which began with the first consultation in July 2022 [3]. Both publications highlighted the challenge of location. One of NESO’s three challenges in 2021 was “the need to incentivise assets to locate and dispatch where they can minimise whole system costs” and they concluded that “current price signals do not incentivise efficient locational dispatch”. The UK Government’s consultation identified how we get “more accurate price signals and the benefit for consumers” and “how to deliver more accurate locational signals” as two of its core cross-cutting questions.

[4] Prior to October 2024 the GB electricity system operator was part of National Grid and referred to as ESO or National Grid ESO. Since October 2024 its name and remit have changed and it has become the National Energy System Operator (NESO). For ease of reference this report will use the name NESO to refer to all activities of the GB electricity system operator, past, present and future, unless there is specific need to differentiate.

Locational signals are often described as having two effects. One is on investment decisions and is about affecting what type of assets are built in which location. The other is on dispatch decisions, with signals impacting how existing assets operate based on their location relative to constraints. The second REMA consultation begins its discussion of options for sending more efficient locational signals by drawing a clear distinction between these two effects. It then asserts that alternatives to locational wholesale pricing may be less potentially beneficial because “they have limited potential to send operational signals – which make up a large proportion of the benefits of locational pricing”. (This report discusses the interaction between investment and operational locational signals in section 2.1.4 and concludes that the situation is more complicated than the binary distinction drawn here).

Whilst it may be useful to split market reform challenges into investment and operational components, that division risks obscuring the overall challenge, which should focus on total costs. The second REMA consultation does identify that challenge in the wider reform context, stating in its introductory section that UK Government aims to “deliver our power sector objectives at the lowest overall system costs, taking account of both cost of capital and system operational costs” [4]. However, it does not acknowledge or explore these interactions in any depth in its section on locational signals.

The scope imposed by REMA means discussions tend to focus on the costs associated with the activities of market participants, but there is a further element of the overall cost challenge: investment in transmission network infrastructure. This is acknowledged by REMA but it sits outside of the review’s scope. The summary of responses to the first REMA consultation noted that respondents highlighted the need to accelerate the build-out of transmission infrastructure [5]. The second consultation discusses the need for increased transmission investment, pointing towards the UK Government’s ‘Transmission Acceleration Action Plan’ [6]. At the same time as highlighting – and apparently accepting – the need for substantial investment in enhanced transmission network capacity, it notes that “work progressed under REMA will reduce the amount of additional investment needed in networks by lowering peak demand and reducing costly network upgrades”. Whilst true, the consultation fails to recognise that the relationship between network capacity and total cost of electricity is two-way and that further network upgrades will reduce the value of locational reforms which might be implemented through REMA.

The sensitivity of the value that locational signals can deliver to transmission investment is clear from several studies. FTI Consulting’s analysis of zonal and nodal pricing, carried out for Ofgem and published in 2023, includes the results of scenarios with two different transmission network backgrounds. This shows that consumer benefits from transitioning to a locational wholesale market are significantly lower where transmission investment is accelerated. For example, zonal market consumer benefits are £18.7 billion for their core scenario with additional ‘HND’ network investment compared with £30.7 billion without the additional transmission [5]. More recently, work by LCP Delta for SSE [7] has repeated analysis conducted earlier in the year for UK Government [8] but includes updated transmission network plans with greater transmission investment during the 2030s.

These results show a significant reduction in the benefits of moving to zonal pricing: reducing savings from between £5 and £15 billion over the period 2030-2050 with previous network plans reduces to between £0 and £11 billion with updated plans.

These two sets of studies focus specifically on quantifying the benefits of locational wholesale pricing. However, the same arguments can be made for alternatives as well. One of the main locational benefits that REMA aims to deliver is a reduction in the cost of transmission constraints. NESO's recently published Clean Power 2030 Advice [2] illustrates the impact that greater or faster transmission build-out will have on these. Its high-level results show that transmission constraint costs in 2030 would range from £12.7 billion if there is no further development of the transmission network beyond today, down to £1.9 billion if potential projects that could be accelerated for delivery by 2030 were completed. A further study by AFRY on an enhanced national market is expected in early 2025.

The implication of these studies is that, whilst it may be useful to leave the process of transmission planning outside the scope of REMA, it is critical to remember that it is the totality of costs that we are aiming to minimise including: (a) commercial investment costs of assets framed by the general set of electricity commercial and regulatory arrangements; (b) operational costs of those assets; and (c) investment in network infrastructure. This relationship is illustrated in Figure 1.

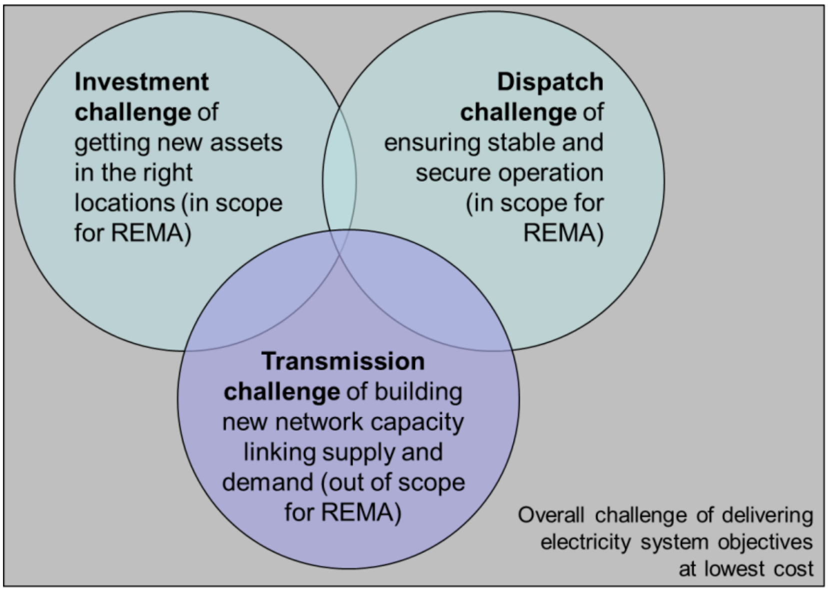

Figure 1: Three components of the locational challenge that REMA is attempting to solve

1.3.2 Frameworks for delivering locational signals: locational wholesale pricing or reformed national market

The locational signals debate has polarised around two approaches: locational pricing in the wholesale energy market, and 'alternative approaches' which retain and reform a wholesale market based on a national price. Most of the quantitative analysis has focused on the first of these options – locational wholesale pricing – for which pre-existing computer simulation packages exist which allow for the configuration of a model to estimate, under certain idealised conditions, costs and benefits of these reform options. Examples of this approach include the FTI and LCP Delta analysis discussed above.

There has been some work that has attempted to quantify how the benefit of moving to locational pricing is affected by improving dispatch or redispatch arrangements within the current system. One of the most significant impacts could be improvements to the way in which interconnectors are dispatched. The most recent LCP Delta analysis explores the impact of improving interconnector redispatch and finds that reforms, within a national wholesale market, to allow redispatch of just a quarter of each interconnector's capacity in line with GB system constraints could reduce the benefit of moving to zonal pricing from £11 billion to £3 billion over twenty years [7]. This points to the outsized importance of interconnector flows in the delivery of an efficient final system dispatch.

Besides the qualitative studies on locational wholesale pricing, several qualitative studies have thought in more detail about the technical requirements needed for both locational wholesale pricing and the alternatives.

In terms of locational pricing: a detailed review of international experience and of the potential challenges and opportunities within the GB context [9] concluded that locational pricing is likely to be limited in its ability to influence siting in GB, could increase the cost of capital for generators, and that significant progress and innovation would be needed to develop processes capable of operating locational pricing within GB. However, it also noted that it would have the potential to improve the efficiency of utilisation of system resources.

Explorations of what might be included within the scope of an alternative model include a review by Frontier Economics of options to improve balancing in the GB system [10]. This presented a list of reform options such as changes to the way BM Bids and Offers are submitted, improvements to the information flow to and from the NESO control room, reforms to encourage more accurate submission of information, moving gate closure and moving from pay-as-bid on Balancing Mechanism Bids and Offers to pay-as-clear. Another report by AFRY [11] compared four future models, two of which were based on a nationally priced wholesale market, and two on a zonal locational market. Of the two national pricing models presented, one involves a move to central dispatch and the other retains self-dispatch. The study did not come to a firm conclusion, but suggested that enhancements to the existing national self-dispatch could be the most attractive option.

As of autumn 2024, there is no clear consensus on which of the two approaches – locational pricing, or an alternative – is most likely to deliver our electricity system objectives of delivery of energy at minimum cost, with sufficient security of supply, and in an environmentally sustainable way with low (zero) carbon emissions (electricity system objectives are discussed in more detail in section 2.2).

1.3.3 The developing context

The current status of the locational signal debate is that, following the second REMA consultation, UK Government aims to make a series of decisions about reform of the electricity system commercial and regulatory framework in the near future. However, there has been significant development of the context within which REMA decisions will need to be implemented. These developments include:

- In October 2023 National Grid ESO transitioned into the National Energy System Operators (NESO), extending its remit to include a 'whole energy system' element and a responsibility to advise on a range of energy system issues, including electricity markets.
- The new UK Labour Government, elected in July 2024, introduced an ambition to accelerate the near-full decarbonisation of the electricity system, from 2035 under the previous government, to 2030 [12].
- UK Government commissioned NESO to produce advice on how to reach its ambition for 'clean power' in 2030. That advice was published at the end of October 2023 [2]. It highlights that there is uncertainty around future market investments and that this could act as a barrier to meeting the ambition. The advice highlights REMA as one element of that uncertainty. It notes that a "locational pricing model is likely the best way of mitigating the risks and maximising the opportunities of a decarbonised power sector". However, it also notes that "any such change would need to be accompanied by clarity on changes to other investment support elements of the market (e.g. CfDs, Capacity Market etc.) and any transition arrangements". Introducing locational wholesale pricing is likely to take at least five years, meaning that a new market framework is unlikely to be delivered ahead of 2030 and, as such, a decision on whether to introduce locational pricing will only directly affect operation after the Clean Power 2030 delivery date. Any decision will, however, influence investment over the next five years as investors look at the likely timescale of returns to their investment throughout the 2030s and beyond. NESO's report discusses the need to ensure investment in renewable generation, supply-side flexibility, low carbon dispatchable assets, and networks. It also highlights some of the non-energy elements of electricity system operation, noting the importance of developing voltage, stability, reserve and response markets.

- The UK Government also commissioned NESO to develop a Strategic Spatial Energy Plan (SSEP) [13]. This was an opportunity for the Government to provide clarity as to the scope of strategic planning and its relationship to markets. In terms of network investment, the commission makes the role of the SSEP clear: it is expected to feed directly into the Centralised Strategic Network Plan (CSNP). However, the relationship between the SSEP, the wholesale energy market and the wider electricity system commercial and regulatory framework is less well defined. The commission states that the SSEP "will sit alongside and grow with future government policy and market-led interventions; it is intended to be complementary to these, providing a more strategic approach to spatial planning, and become part of the framework of planning systems across GB." It further describes the role of the SSEP as to "support the UK, Scottish and Welsh governments and regulators, in tandem with energy markets, to assess the optimal locations, quantities and types of energy infrastructure needed to transition to low carbon energy." The relationship between strategic planning, the wholesale energy market and regulatory and other policy cash flows is important when considering the most appropriate way to provide locational signals. The present report explores this further in Section 2.5.

1.4 A summary of relevant publications

The remainder of this section is a brief summary of reports published over the past year that are relevant to this work:

- The two REMA consultations published by the UK Government, together with a summary of responses to the first consultation, have provided the public-facing scaffold for the debate [3] [4] [5].
- The second consultation included a number of supporting research papers, including modelling by LCP Delta and Grant Thornton of the potential economic impact of moving to zonal pricing [8] and a summary of incremental reforms that could be applied alongside a national wholesale market by Arup [14].
- Commissioned by SSE, LCP Delta updated their REMA analysis to reflect the Beyond 2030 [15] network plans, published by NESO in April 2023 [7].
- NESO has continued to develop its market reform programme through phases three [16] and four [17] and is now engaged in a scheduling and dispatch phase [18]. The latter includes analysis by AFRY.
- Ofgem presented its view of locational wholesale energy pricing in October 2023 [19] alongside modelling by FTI Consulting [20] and three academic reviews of the FTI Consulting work [21] [22] [23].
- Scottish Power commissioned Frontier Economics to assess options for incremental reform alongside a national wholesale market, published in April 2024 [10].
- Frontier Economics to review the implication of locational marginal pricing for the cost of capital, published in 2022 and updated in 2023 [24] [25].

- AFRY undertook a series of studies on behalf of multiple industry clients, including an analysis of national and zonal market designs, published in May 2024 [11].
- Regen have published an independent 'thought piece' with a detailed review of alternative arrangements [26].
- The Energy Landscape has presented opportunities for using constraint management markets for Scottish Renewables [27].
- Researchers at the University of Strathclyde carried out a detailed exploration of the potential opportunities and challenges associated with locational marginal pricing, published in early 2023 [9].
- The Energy Landscape produced a paper on potential interconnector reform with Scottish Renewables in December 2024 [28].

1.4.1 The second REMA consultation

The consultation takes, as its starting point, the centrality of markets for the electricity system and an explicit statement that UK Government does not believe the current electricity market framework will deliver the secure, clean, low-cost electricity system we need in the future. The key challenges it highlights include:

- The future market will be less centralised, generation will be located further from demand, there will be an increasing number of stress events of a variety of types, and immature technologies need bespoke support.
- It acknowledges the UK Government's commitment to develop a strategic planning approach to the energy system, but the consultation remains focused on market led approaches and little is said on the interaction between the two.
- The location of supply and demand is increasingly at odds and this puts a strain on network infrastructure, which will manifest as an increase in the number of periods of network constraints.
- There is a lack of coordination between three domains where locational signals emerge – planning, networks, markets – could result in locational signals being blunted or inefficient.
- The consultation suggests that day-to-day operation may be where most of system and consumer benefits may lie.

The consultation lays out, at a high level, options for both zonal wholesale pricing and alternatives. However, there was insufficient detail to understand how either option might work in practice. The key options put forward for the 'alternative' package are:

- **Using Ofgem's pre-existing network charging reform programme (option A):** The consultation concludes that the Government will work with Ofgem who have agreed a programme of long-term TNUoS reform to the same timeframes as the REMA process.

- **Reviewing Ofgem's transmission network access arrangements (option B)**: options under consideration:
    i. **Administrative allocation of firm access for new users** described as offering new connectees the choice of non-firm access rights, potentially for a time-limited period, in return for faster connections.
    ii. **Auctions for firm access rights for new users.**
    iii. **Local firm access rights only,** although the consultation suggests that to be viable, this would need to be combined with zonal pricing.
    iv. **Removal of financial access rights to the entire network for all users (including existing users)** although the consultation notes that this could require central dispatch to avoid the ESO having to choose who to constrain off based on non-financial parameters.
- **Expanding measures for constraint management (option C).**
- **Optimising the use of cross-border interconnectors (option D).**
- **Introducing a locational element to the capacity market (option E):** however, the consultation "discounts introducing a locational element to the capacity market as a standalone option."
- **Introducing a locational element to the CfD (option F):** the consultation rules out developing this as a primary option for sending locational investment signals but does leave the option open as part of wider considerations around the design of the CfD and its allocation process more generally.

Overall, the REMA consultation lacks sufficient detail on the options to come to a well-justified decision on which is the most appropriate way forward. The consultation suggests the need for a more comprehensive and standardised assessment of options, and consideration of those options from the perspective of a range of different asset types. Although the second consultation discusses risk in significantly greater detail than the first, its reliance on an evidence base drawn from single-scenario studies falls short of quantifying, or sometimes even properly identifying, the risk and uncertainty arising from locational signals that intrinsically depend on comprehending the possibility of a range of outcomes.

1.4.2 NESO's scheduling and dispatch work informed by analysis by AFRY [18]

The scheduling and dispatch workstream reflects NESO's view that GB market dispatch is not working as intended. This is because, in the view of NESO, they are becoming a 'central scheduler' and that this is contrary to their intended role. They are concerned that the overlap between wholesale market trading and NESO redispatch is growing.

NESO commissioned AFRY to carry out a case for change analysis. This analysis concludes that:

- **There is a strong case for change:** which includes both locational and system-wide issues.
- **There are three areas of concern: incentives, visibility and access, and intertemporal issues**: all three contribute to issues with locational dispatch, which impacts on network congestion.
- **There is a lack of locational signals in the wholesale energy market**, the reserve markets, and in imbalance pricing. Hence, there are very few locational signals affecting operational decisions.
- This has contributed to the growth of locational balancing actions and associated costs.
- Market participants' decisions on which units to dispatch do not internalise information on whether that dispatch will be physically feasible. This creates challenges for the NESO in at least four ways:
    i. **The general market dispatch of assets is out of line with system limits** even where there is high confidence in the operational conditions for the relevant settlement period.
    ii. The incentives on market participants with multiple assets **to balance their portfolios nationally** can exacerbate constraints based on what specific assets those portfolios choose to operate.
    iii. Market participants may successfully use **'NIV chasing' strategies**, particularly with embedded assets, in a way that helps minimise the system Net Imbalance Volume (NIV) on a national scale, but they can do so in a location in which the action exacerbates a network constraint. This can create very short notice, and difficult to forecast, changes in the net demand seen by the ESO control room.
    iv. **Interconnector dispatch does not take account of locational constraints**, and changes to dispatch increasingly occur in the last hours before gate closure.

- These issues create several related effects:
    i. **The volume of redispatch for transmission constraints is very high,** significantly higher than expected under the NESO's original residual-balancer role. The volume of actions NESO needs to take, and the need to take most of these after gate closure, could mean it is physically challenging to implement a sufficient volume of actions. This is a security of supply issue.
    ii. **The cost of redispatch for transmission constraints is very high**. Therefore, even if redispatch under current arrangements is physically possible, it leads to a failure against the cost-minimisation objective.
    iii. The increase in variability of constraints needed on intraday timescales and even after gate closure means that the ESO has to take decisions whilst there is still significant uncertainty in how market participants will operate.
    iv. The cost of providing response and reserve is increasing.

- The report also highlights that there is a lack of locational signals in the reserve markets, which further increases the cost of reserve provision. The market is not incentivised to provide this flexibility where it is needed, and often headroom and footroom held for flexibility in response and reserve can be sterilised.

1.4.3 Frontier Economics analysis for Scottish Power [10]

Frontier Economics was commissioned by Scottish Power to review options for improving operational efficiency without implementing locational pricing. The report:

- **Identifies three drivers of dispatch inefficiency**: **information** (insufficient data for optimal dispatch), **optimisation** (the optimisation process fails to deliver an efficient dispatch because of simplifications, modelling assumptions etc); and **implementation** (inability to implement the outcome of an optimisation).
- **Limitations on information:**
    i. Balancing Mechanism parameters aren't necessarily an accurate reflection of technical limitations faced by power stations (i.e. those parameters might be set for other reasons).
    ii. Parameters provided by storage assets do not reflect their true capabilities.
    iii. **Pay-as-bid** on Bids and Offers means participants are incentivised to bid just below the expected marginal Bid/Offer to capture infra-marginal rent, rather than incentivised to name prices based on their short-run marginal costs.
    iv. **Physical Notifications are often inaccurate** because of limited incentives to get Initial Physical Notifications (IPN) and Final Physical Notifications (FPN) right.
- **Limitations on optimisation:**
    i. **NESO currently does not operate a national nodal optimisation algorithm** to choose which Balancing Mechanism Bids and Offers to accept. Instead, it takes a more 'local' approach, focusing its optimisation in areas in which it identifies constraints.
    ii. Currently, NESO does not optimise the operation of storage over multiple periods.
    iii. Market participants' decisions over wholesale trading and setting their physical positions may take into account their expectations for NESO's locational balancing requirements.
- **Limitations on implementation:**
    i. **Practical challenges where larger units are selected over smaller units** in order to deliver the greatest impact within a limited number of individual actions. Smaller assets are becoming a bigger share of balancing resource, so the impact of this inefficiency is growing.
    ii. Limited ability to redispatch interconnectors.
- The report proposed potential reforms based on these three drivers. These include moving to pay-as-clear BM pricing, moving gate-closure forward (longer balancing mechanism timescales), incentivising more accurate initial and final

physical notifications, and improvement to NESO control processes. It also gives options specifically aimed at improving interconnector dispatch.

1.4.4 Frontier Economics analysis for SSE on the implication of locational pricing on cost of capital [24] [25]

The initial report, published in 2022, highlights that although investors currently face volatility in TNUoS charges, the introduction on a locational pricing regime may be expected to lead to investors facing an even greater risk. It highlighted that, relative to TNUoS, locational pricing could be more volatile, impacted by a greater number of factors and be difficult for investors to predict. It suggested that the cost of capital may increase by 2 – 3 percentage points as a result of a move to locational pricing.

The conclusions of this report were challenged, and in 2023 Frontier published a follow up responding to those challenges. In particular, the 2023 report notes challenges from FTI Consulting that investors could diversify away any increased risk, removing any impact on the cost of capital. However, Frontier argues that this may not be the case. They hold that FTI's argument is based on a set of assumptions which are sufficiently unlikely to hold in practice, and that, at least in the short term, investors would be unlikely to be able to assemble a sufficiently wide portfolio to diversify the risks.

1.4.5AFRY multi-client study [11]

Since 2022 AFRY has been working with multiple clients to develop thinking about wholesale market reform. In this report, they explore four options, including two which have a national wholesale market:

- Operational inefficiencies emerge from three sources: inadequate market incentives on market participants, a lack of visibility of the system by the NESO, and an inability to access balancing resources and limited ability to manage intertemporal constraints (whether those intertemporal constraints are locational or national).
- The report highlights the interactions between 'efficient signals' and other considerations, such as investability and practicality. For example, it notes that central dispatch would not fully resolve locational management issues, but that both zonal and central dispatch market designs would affect risk for market participants and hence, investability.
- AFRY propose two models which could improve locational signals whilst maintaining a national wholesale market: one (enhanced national) retains the decentralised energy market, the second (national centralised) moves to centralised day-ahead dispatch.
- In the enhanced national market, key reforms include: introduce an explicit pay-as-clear balancing market, the introduction of pre-gate-closure constraint

markets and enhanced constraint intertrip systems, inclusion of interconnector assets as BMUs (rather than simply each of the market participants trading across the interconnector). They also place a focus on standardising signals across distribution and transmission networks and on developing new tools for NESO to adjust interconnector flows in cooperation with stakeholders in connected markets.

1.4.6 FTI LMP report for Ofgem [20]

FTI carried out an extensive study modelling the economic impact of a move to nodal wholesale pricing for Ofgem:

- The report provides background information for the development of the GB electricity system. It highlights particularly that in the original design of New Electricity trading Arrangements (NETA) “the role of the SO was intended to be that of a residual balancer” and whilst this was the case during the first decade of NETA “the SO now has a very material, and apparently non-residual, role in balancing the system”.
- FTI are concerned about the forecast increase in constraint costs noting that, at the time of their report (written in 2023), “constraint management costs are not expected to return to the levels observed at the beginning of this decade (let alone to the levels observed only five or 10 years ago)”.
- One conclusion that FTI reach is that locational pricing will reduce the level of transmission investment required. This may be true theoretically. However, real-world effects, such as the feasible timeline for delivering new transmission capacity could easily be instrumental in determining outcomes over the next decade or more.

FTI do present two illustrative ‘cost of capital’ impacts, referring to the investment challenge shown in Figure 1 above (pg 17). They conclude that across the scenarios they used that an increase of cost of capital for as low as 1.39% for zonal and 2.56% for nodal would negate any theoretical savings of the move to locational pricing. The exact value is scenario dependent. However, it should be noted that FTI’s analysis used transmission build-out plans from 2022, whilst more ambitious plans have now been laid out in the Beyond 2030 publication.

1.4.7 LCP Delta and Grant Thornton’s analysis for UK Government [8]

Alongside the second REMA consultation, UK Government commissioned a number of research studies. Work led by LCP Delta aimed to replicate the type of analysis that FTI had carried out for Ofgem, but limited to zonal rather than nodal locational pricing, and using updated scenarios:

- In analysing the potential impact of moving to zonal pricing, LCP Delta modelled three types of inefficiency: **an inefficiency in how interconnectors respond to locational constraints**; **an inability to effectively dispatch storage**, leading to storage being 'skipped' in the BM, **and a disconnect between BM Bids and Offers and the prices that should theoretically have been offered for units** in a competitive market.
- Their modelling identifies a potential £15 billion saving between 2030 and 2050 of moving to zonal pricing compared with the status quo, although it identifies that if dispatch inefficiencies are removed from the current system, the savings from moving to zonal wholesale energy pricing reduce to £5 billion. The £10 billion difference appears to **be approximately £8bn facilitated by location-aware interconnector dispatch and £2 billion from more effective storage dispatch.**
- However, the published report included only limited information on the assumptions and scenarios used. For example, it did not provide a breakdown of generation capacity by location, or a clear breakdown of assumed transmission capacities – a parameter which is notoriously hard to estimate. This raises concerns about the validity of the outputs.
- LCP Delta also carried out illustrative analysis showing the impact of the cost of capital increases. Their results suggested an increase of between 0.3 and 0.9%would be sufficient to remove the cost-reduction benefits of moving to zonal.

1.4.8 Regen's Progressive Market Reform paper [26]

Regen laid out a 'progressive market reform' agenda in summer 2024 which includes a discussion of options that could be implemented alongside a national wholesale market and deliver a more incremental approach to reform:

- Regen argues in favour of alternatives to locational wholesale pricing. The paper argues the benefits of nodal and zonal pricing have been overstated because of the scenarios chosen and modelling methodology used, and that current arrangements are not fundamentally broken.
- They propose ten principles which highlight the risks associated with moving to locational wholesale pricing and argue that competing considerations such as the impact on cost of capital and deliverability whilst at the same time requiring major investment to deliver net zero, outweigh any economic efficiency benefits that wholesale energy pricing may deliver.
- The paper proposes a raft of interventions which could be introduced incrementally. On location, it notes the importance of aligning locational signals with any strategic plan and puts a spotlight on non-financial locational signals and those that come from outside the electricity system commercial and regulatory framework. It argues that, together, these provide a strong investment-timescale signal, but agree that improvements on operational timescales would be useful. Regen's proposals include making the Balancing

Mechanism and reserve markets explicitly locational, and placing a focus on local supply and opportunities to coordinate dispatch of embedded assets at distribution level.

1.4.9 Constraint Management Markets report by The Energy Landscape for Scottish Renewables [27]

A report commissioned by Scottish Renewables in early 2024 considered how pre-gate closure redispatch could be improved by the introduction of new constraint management markets either on short (day-ahead and intraday) or long (months and years ahead) timescales:

- The report argues that insufficient effort has been made to explore the potential for constraint management markets. It notes that constraint volumes and costs (however those costs are allocated) will probably continue to rise, and that higher constraint volumes may be the right outcome when aiming for minimisation of total overall system costs. The corollary is that there is significant value in looking at ways to improve how constraints are managed and particularly to provide new frameworks that ensure this can be delivered in a cost reflective way.
- As well as proposing the outline of a constraint management market model, it notes that there could be opportunities for integrating interconnectors and therefore supporting more effective locational dispatch of interconnector flows.
- It also acknowledges that, because constraint management markets would run alongside the wholesale energy market, there is a risk of gaming, with market participants potentially participating in both concurrently. There are opportunities to design the markets so that these risks can be minimised and managed. However, it will be important to explore both the risks and the mitigations.

1.4.10 University of Strathclyde locational wholesale energy pricing report [9]

In 2023, the University of Strathclyde carried out a detailed review of locational energy pricing in order to provide a critical assessment of the benefits and opportunities that such an approach could deliver in practice. It was designed to complement the quantitative approaches of FTI and others whose modelling implicitly had to assume that appropriate processes could be implemented:

- The report focused on the potential for nodal or zonal LMP in the GB system and noted that while LMP could improve dispatch for both generation and flexibility, it concluded that there were also significant concerns with the potential approach. In particular, it highlighted the potential impact on investability for generators and a lack of detailed exploration of the impact on the demand side and how necessary supplementary tools like markets for the trading of Financial Transmission Rights (FTR's) would be designed.

- It concludes that whilst there are major potential issues with LMP that would need to be addressed, there was also (at the time of publication in early 2023) a lack of a well-articulated alternative.
- Whilst there have now been several reports looking at some alternative options, the position remains largely the same: options for implementing locational wholesale pricing are well defined because existing systems use them elsewhere in the world. However, GB is one of the first systems to experience strong locational dispatch issues within the context of a very highly decarbonised electricity system and driven by intermittent, zero marginal cost renewables. Because GB is at the forefront of delivering low carbon electricity through a system based largely on variable renewables, wind and solar, it is also one of the first electricity systems to face the scale of challenges that we now see.

1.5 Interconnectors: a special case?

One particular area of interest is cross-border interconnectors. These assets (or the entities that trade across them) have an ambiguous role in our electricity system: they are treated as market participants, capable of buying or selling energy within our market or providing system services. However, the assets themselves are inherently 'network' assets: they transfer energy from one place to another rather than generating, consuming or storing it. In Europe, cross-border network capacity is largely treated as a network asset. It is usually owned by the national Transmission System Operator; its costs are recovered by the same processes that recover other transmission costs; and flows across them are set via market coupling algorithms rather than by explicit nominations separated from energy market trading. In short, they are treated as market facilitators rather than market participants.

One reason for this difference is that in GB, interconnectors are commercial profit-making projects rather than regulated network assets. Therefore, they are expected to operate in a competitive context.

However, GB's previous participation in the European Internal Energy Market has left us with a set of arrangements for interconnectors which reflect their typical status in European systems and prohibit the application of some regulatory cash flows through which locational signals could be delivered. The Trade and Cooperation Agreement (TCR) [29] signed between the UK Government and the EU as part of Brexit arrangements, committed us to maintaining some of those arrangements.

At the same time, leaving the Internal Energy Market has fragmented our cross-border trading arrangements, leading to significant differences between how flows are set across the nine existing interconnectors and the opportunities for how these can be redispatched.

To summarise current arrangements:

- Interconnectors connecting to France, Belgium, Netherlands and Denmark use day-ahead and intraday auctions with flows set explicitly by individual market participants buying and selling in both markets and nominating flows on the interconnector, having previously procured the rights to interconnector capacity from the owner. The approach allows NESO to undertake trading in intraday markets with individual market participants to attempt to change flows set in the day-ahead market, and to do this to solve locational issues.
- The interconnector connecting GB to Norway is dispatched through a day-ahead implicit auction, which links the flows to power exchanges in Britain and Norway's NO2 zone. There isn't a market-based option for NESO to redispatch this interconnector, but it can use Net Transfer Capacity restrictions to limit the capacity allowed to flow; if used, NESO must pay the cost of lost revenue.
- The interconnectors connecting to the system on the Island of Ireland – both the Republic and Northern Ireland – are dispatched by intraday implicit auctions. The only redispatch option currently available to NESO is to use a Cross Border Balancing (CCB) mechanism, which tends to involve relatively high prices.
- Under EU rules and now agreed through the TCA, interconnector flows are not charged Transmission Network Use of System Charges (TNUoS) or Balancing System Use of System Charges (BSUoS), and Transmission Loss Factors (TLFs) are not applied to their flows.
- Interconnectors and market participants with nominations across them are largely unable to participate in the Balancing Mechanism or other post-gate closure mechanisms because GB sits outside EU balancing frameworks.

The difficulty in applying locational signals to interconnectors through regulatory cash flows or balancing mechanisms means that it is fair to call interconnectors a special case.

Some have argued that a move to locational wholesale pricing is the only way to provide an operational-timescale signal to interconnectors. However, this report suggests that there is at least one viable option that should be considered alongside a national wholesale market.

1.5.1 The Energy Landscape interconnector recommendations report for Scottish Renewables [28]

During spring 2024 Scottish Renewables convened discussions with the interconnector community in order to better understand options available to improve interconnector planning and dispatch. This discussion included representatives from GB interconnector developers, owners and operators along with an European TSO, GB generator and supply companies and renewable trade associations. The report includes five recommendations. The report highlights the importance of putting interconnector issues in the wider context of the socio-economic benefit that they deliver and the optionality that they provide. The five recommendations are:

- Improve locational investment signals through a strategic plan for interconnectors
- Improve locational dispatch through coordinated approaches with connected system operators in line with examples happening in Europe
- Ensure GB forward-trading evolves to align with European market developments
- Co-develop solutions with interconnected countries
- Prioritise reintegration into the Internal Energy Market.

2 How to think about locational signals

Locational signals are inherent in almost every aspect of trading goods and services. The costs of transporting a commodity or the use of infrastructure involved in delivering it depend on the relative location of supply and demand, and in competitive and unregulated markets, those costs tend to be naturally distributed in cost reflective ways. For example, in the retail fuel market (for example petrol or heating oil) the locational costs and benefits, such as those associated with transporting fuel to particular parts of the country, are internalised into the price paid by end consumers.

Markets play a central part in the trading of electrical energy and of the services needed to keep the electricity system operating. However, the nature of electricity and the electricity system means that there is a limit to the role of markets. Major parts of the electricity system are natural monopolies, namely the provision of network capacity and of system operation, and many of the locational challenges facing the system depend heavily on these monopoly elements. The essential-service nature of electricity also means that government and Ofgem regularly limit the role of the market where it is seen to fail in delivering affordable and reliable access to energy, even for a relatively small number of consumers. For example, UK Government subsidises the costs of the north of Scotland distribution network to “protect domestic and non-domestic consumers from the high costs of distributing electricity in the North of Scotland” [30], something estimated to be worth £60 per year to a typical household.

The most appropriate application of locational and other forms of signals to reflect costs associated with different locations is a question faced in respect of several national infrastructure assets. Despite often similar theoretical underpinnings, our answers to the question are often very different in different contexts. For example, in Britain, with very few exceptions such as occasional bridge and tunnel tolls, drivers do not face locational road charges, only the non-locational vehicle excise duty [31]. And in Scotland, for most domestic users, the costs of water (both the cost of connection to the water and sewage networks and the use of water itself) is paid for through a fixed annual fee with no cost-reflective elements at all [32]. By contrast, in the electricity system, we find it appropriate to charge a unit rate for the commodity (energy) and aim for a system with significant locational charges to pay for the infrastructure that supplies it.

Understanding the role of locational signals in the future electricity system involves consideration of several underlying factors. Firstly, it is important to fully and clearly articulate the ultimate objectives of the electricity system and the purpose to which locational signals are being used. Secondly, the context needs to be understood as including how location affects investment and operation today. This context needs to consider locational factors from beyond the electricity system itself. This will include the effect of weather, geography, demography and the influence of other policy factors, such as planning policy. It is also important to consider ‘locational signals’ in the broadest sense of the term, ensuring that it includes ways to influence locational investment and operation including incentives, rules and mechanisms (see Section 2.1).

This section provides an overview of this context, beginning with a discussion of the nature of different types of locational signals, before moving onto the purpose that they can be put to and then providing an overview of locational signals today. It concludes with a discussion of the role of strategic spatial planning and the implications of NESO's recent Clean Power 2030 advice.

2.1 The nature of locational signals

There are many ways to characterise locational signals. These characteristics can help to inform which options may be most useful and how different locational (and non-locational) signals will interact. Some of these characteristics, such as the distinction between operational and investment timescale signals, are already an important part of the debate. Others, such as the distinction between signals which affect expected values of future cash flows and those which affect the level of uncertainty in those cash flows, have been less clearly identified. Figure 2 summarises six sets of characteristics and these are explored briefly in the following subsections.

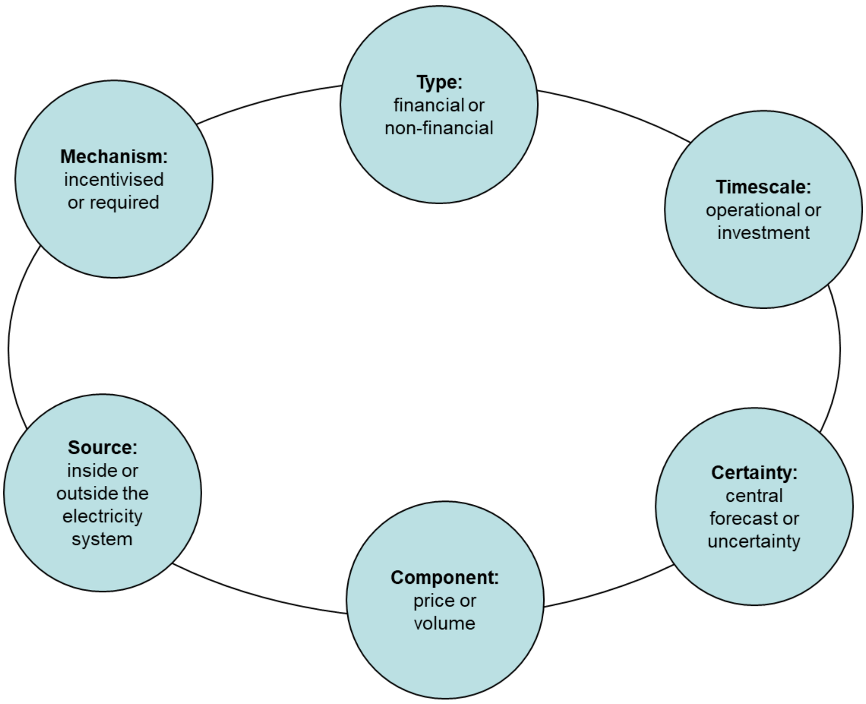

Figure 2: Useful characteristics for analysing locational signals

2.1.1 Source: inside or outside the electricity system commercial and regulatory frameworks

The locational signals affecting any electricity asset consists of a mix of signals from within the electricity system itself and those from outside.

Signals external to the electricity system include the cost associated with buying, transporting and installing the asset itself. For example, an onshore wind farm in a remote and rural location will have higher installation costs than one close to a major turbine manufacturing plant or port. With generators, these signals include the locational cost or availability of the underlying resource, whether fuel (gas or biomass for example), or renewable resource (average wind speeds or solar irradiance). For consumers, they include the locational costs associated with using or selling the output of the processes which electricity is used to run; a factory, for example, needs to consider the cost of transporting its widgets to their users. There are often other policy and regulatory frameworks such as those associated with planning permission or relevant environmental regulations which create important locational signals, but ones that come from outside the electricity system.

It would be difficult to provide a comprehensive review of all types of locational signals coming from outside the electricity system, and many will be beyond the ability of government or the industry to reform. However, it is important REMA doesn’t ignore these locational signals, but identifies those that are important, and considers how they will interact with signals designed into the electricity system itself.

2.1.2 Type of signal: financial and non-financial signals

Financial signals are those which affect cash flows. A locational financial signal means that similar projects in different places either face different costs or will receive different revenues if they act in the same way. By contrast, there are a wide range of non-financial locational signals which can have a significant impact on where market participants connect and how they operate. Examples of non-financial signals include access to the seabed for offshore wind farms, the likelihood of gaining planning permission and consent, and the availability of grid connections. For some of these examples, there may be a financial element involved – for example, there is no access to the vast majority of the seabed as it isn’t included in leasing rounds, but where leases are offered, these are usually allocated by auctions. For others, it may be possible to present them in financial terms (the financial implication of a location where it is not possible to get a grid connection is that revenue equals zero). However, they are most easily understood in a non-financial way.

REMA should consider both financial and non-financial signals.

2.1.3 Approach: incentives or rules

Section 1.1.2 introduced the idea that investment and operation can be influenced through incentives, rules and mechanisms. Incentives encourage, but don’t require, market participants to act in a certain way. Rules take the form of specific requirements or prohibitions and usually come with both a penalty and a broader expectation that they are obeyed. Mechanisms are essentially packages of incentives and / or rules which structure their use. The term ‘signal’ can sometimes be perceived to imply only ‘incentives’, but it is important that rules and mechanisms are also considered.

As an example, in an operational timescale, locational prices incentivise operation in a particular way: a high locational price at a particular time incentivises generators to run and consumers to turn off; a low locational price discourages generators whilst encouraging consumers. By contrast, non-firm access provides a rule that gives NESO the right to prohibit operation.

There are other important rule-based locational signals: the need to acquire a seabed lease effectively creates a rule that investment is not allowed outside areas made available by The Crown Estate or Crown Estate Scotland. Grid connection policy can also provide locational rules. The ‘Invest and Connect’ policy used until 2009 prohibited new investment from connecting to the network until wider transmission upgrades were completed. In contrast, ‘Connect and Manage’ allowed connection whilst non-local transmission upgrades were still in development. Similarly, the evolution of connection policy today, and particularly of ‘queue management’, could be used as a locational rule-based tool.

2.1.4 Timescale: operational and investment

Much of the discussion in REMA has differentiated between operational and investment timescales for locational signals. This is a useful distinction. Locational investment signals are those which influence an asset’s investment case and will be part of the considerations made at the Final Investment Decision (FID) before the asset is built. As such, there is no need for investment signals to have any degree of temporal granularity (although they may do). Locational operational signals must have a sufficiently high temporal granularity to influence the operation of an asset, ensuring that it operates in a way that reflects the prevailing system conditions at that location. As such, they are likely to have a temporal granularity on the scale of hours, and often at either settlement period granularity – 30 minutes – or less.

However, the two timescales are not independent and there are important feedback loops between the two (see Figure 3). These include:

- **Investment timescale locational signals impact on what assets get built and where.** This in turn affects what assets there are in the future to respond to operational locational signals. For example, the lack of a strong and practically accessible investment timescale locational signal means that there is limited additional revenue for batteries in Scotland compared with batteries elsewhere in GB (the BM mechanism technically delivers a locational signal as a battery could provide constraint management, however a combination of ‘skip rates’, control room processes, ‘pay-as-bid’ rules and the transmission constraint licence condition, significantly limit the practicality of accessing those incentives). This is despite the reduction in renewable curtailment they could deliver. The result is that even if improved operational timescale locational signals were introduced today, there would be only a limited capacity of batteries to respond in Scotland. This means that delivering sufficient investment timescale locational signals is important to ensure cost-effective future operation.

Operational locational signals aggregate together to create investment timescale signals. For many assets without explicit long-term support mechanisms, investment decisions are made by forecasting future operational-timescale signals. Fossil fuel power stations provide a (non-locational) example. They have tended to rely on the aggregation of operational timescale signals from the wholesale energy market to underpin investment, often combining pure operational signals with hedging provided by the market over a few years. However, in the early 2010s, narrowing national generation margins suggested that this was not sufficient to ensure security of supply, leading to the introduction of the capacity market which provided an investment timescale 'top up'. Another example is the business case for short duration batteries. These assets do not receive policy support payments (and those with discharge durations of less than six hours will also be excluded from the new cap and floor reform). As such, they rely on expected revenue from operational signals in the wholesale energy market, Balancing Mechanism and ancillary service markets.

Practically accessible locational operational signals for flexibility are, at best, weak in GB at present. This limits the interest in locating flexibility in Scotland, despite the significant value that this would create. This situation is particularly worrying in the context of new flexible demands such as electrolysis. The recent Hydrogen Allocation Round 1 process offered support mechanisms to 12 projects across GB [33]. Although there were two Scottish projects this cohort, recent work by one of the present authors argues that there are limited incentives from within the electricity system for these projects to choose to locate in Scotland over other areas of GB in order to benefit from the value they deliver through reducing curtailment [34].

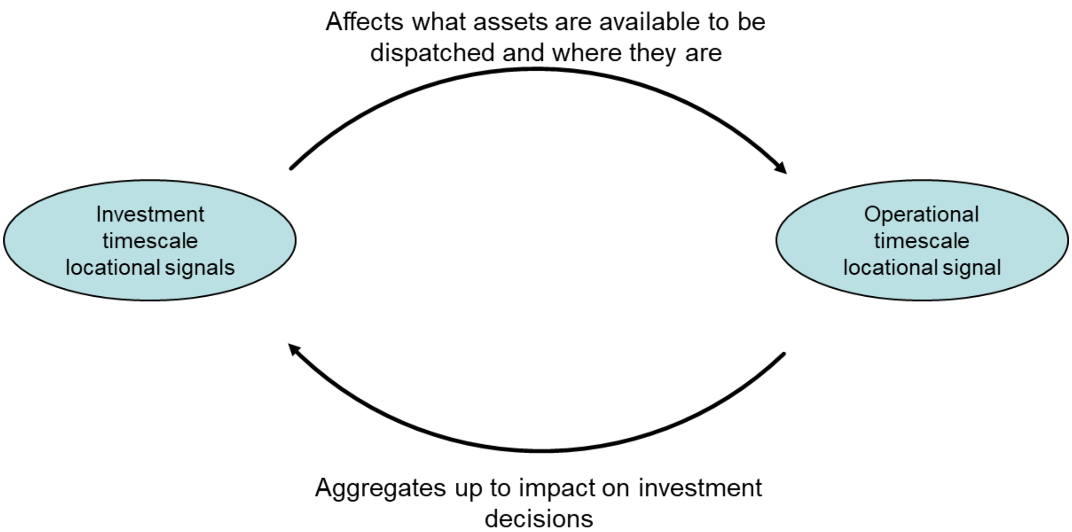

Figure 3: Interactions between operational and investment timescale locational signals

2.1.5 Component: price and volume

Within the category of financial signals, price-based locational signals are those where, within a market, the price varies by location. Volume-based locational signals are those where the quantity of a commodity or service – energy, capacity, frequency response availability – that a market participant can buy or sell at a particular price varies by location.

Signals delivered by both types are important, and many reforms involve an impact on both price and volume. For example, a move to LMP introduces both a locational price signal and, through the removal of firm access rights, a locational volume signal. Similarly, locational signals could be introduced for many of the system services procured by NESO.

Volume signals are most often discussed in terms of generators. The delivery of volume signals to the demand side through the energy market is potentially more problematic. It would involve limiting access to energy and may not be appropriate for some types of consumer in certain situations. For example, limiting access to electricity for domestic consumers would go against the aim of increasing the reliability of supply.

Figure 4 shows the distinction between volume and price, along with the next set of characteristics based on certainty.

2.1.6 Certainty: forecast 'expectation' and certainty

Locational signals usually remain uncertain, at least to some degree, at the point that a decision is made by a market participant. This is clearest in terms of investment decisions where most of the cash flows across the lifetime of the project include significant uncertainty. Even for operational decisions which are made in the days, hours and minutes leading up to dispatch, the decision on when and how to operate is taken in the face of some residual uncertainty.

For example, battery operators will be looking to maximise their revenue across multiple operational revenue streams, including wholesale market trading, intraday market trading, ancillary services and the Balancing Mechanism. However, the route to participate in each of these options occur at different times. Day-ahead wholesale trading (which represents a significant part of battery activity in the wholesale market) involves auctions which clear around mid-morning for all hours of the following day. Therefore, decisions there need to be taken before there is knowledge of the volumes and prices associated with ancillary services, which are set by auctions during the early afternoon for the next day. Finally, whilst Balancing Mechanism actions may, at times, be the most lucrative, they are only available as adjustments to committed positions at gate closure. Each set of operational decisions is taken in the face of uncertainty over the remaining ones.

TNUoS provides an example of the interaction between these two considerations. In 2023 the ESO laid out ten-year projections for TNUoS [35], including exceptionally high charges for generators in the north of GB. Investors may consider these values as akin to an 'expectation' value and on their own, these high forecasts provide a strong locational signal against investment in generation in the north. However, there is also significant *uncertainty* over exactly what the value of TNUoS will be in each zone in the early 2030s. The outturn value will depend on what transmission infrastructure has been commissioned by a particular date, the generation background, levels of demand, and whether the TNUoS methodology remains largely as it is today (or even whether TNUoS continues to exist at all). This uncertainty creates an additional locational signal, with the potential that the uncertainty itself varies by location (whether measured in absolute £/kW terms or as a fraction of the expected value) or where the impact of uncertainty depends on the expected signal: for example, an uncertainty of plus or minus £10/kW could be significantly more material for a project where the expected value is £75/kW compared with a project where the expected value is £20/kW.

Finally, expectations and uncertainty can also apply to rule-based locational signals. For example, if non-firm access rights are used to prohibit operation under certain conditions, investors will need to estimate the prevalence of those conditions in future and their level of certainty over that prevalence.

For any investment or operational decisions, it may be important for assets investors/operators to consider a) the 'expectation' or the central forecast, and b) a measure of certainty, such as the standard deviation of the P90 revenue[5].

The combination of the component (price and volume) certainty (expectation level and uncertainty) and whether this applies to a project's costs or revenues is summarised in Figure 4.

[5] The term P90 revenue is often used in wind farm investment where it represents the revenue that a project might expect to receive in a year where the actual wind outturn is low, to the extent that, statistically it would only be expected to happen in 1 in 10 years – i.e. for 90% of year, the wind outturn would be expected to be higher.

Potential locational signals faced through the electricity system commercial and regulatory framework

	Revenue		Costs	
	Price	Volume	Price	Volume
Expected Quantity	Does the market (or regulated) price for selling a product (e.g. energy, capacity, frequency response) vary by location?	Does the amount of a product that can be sold vary by location?	Does the market (or regulated) price for buying a product (e.g. energy, network access) vary by location?	Does the amount of a product that can be brought vary by location?
Risk (uncertainty)	Is their uncertainty over the future price of a product, and does that uncertainty vary with location?	Is there uncertainty over the amount of a product that can be sold, and does that uncertainty vary with location?	Is there uncertainty over the future price of a product, and does that uncertainty vary with location?	Is there uncertainty over the amount of a product that can be purchased, and does that uncertainty vary with location?

Figure 4: A framework for thinking about price and volume, quantity and uncertainty, revenue and costs

2.2 The purpose of locational signals

The purpose of any element of electricity market and system design must be to deliver overarching societal objectives. In a liberalised electricity system, objectives are achieved primarily by the combined action of market participants operating on a commercial, competitive basis. Therefore, locational signals should drive the behaviour of individual market participants in directions that support the delivery of societal objectives. Whilst simple to state, there are complications and tensions inherent in the market design process.

Firstly, there are multiple societal objectives which the electricity system aims to deliver and these can often be in tension with each other. The core societal objectives are broadly agreed on and articulated as a version of the energy trilemma: delivery of energy at minimum cost, with sufficient security of supply, in an environmentally sustainable way with low (zero) carbon emissions. In addition, there are several other objectives to which the electricity system contributes: economic development, delivery of industrial strategies, regional development, etc. (For a more detailed discussion on the objectives of the electricity system, see the author’s previous work on Locational Marginal Pricing) [9].

Secondly, each objective applies at different timescales and even within a single objective there can be tensions between its delivery on one timescale and another. For example, a particular commercial and regulatory framework may deliver short-term cost savings, but could adversely affect investment in low-cost generation technologies and fail to deliver cost efficiency in the long term.

Thirdly, the delivery of each objective at each timescale can vary across the country. Ensuring a secure supply in south-east England may require quite different interventions to those of ensuring a secure supply in northern Scotland. As an example, schedulable back-up power stations are often maintained on small islands instead of building additional undersea cables, whereas, elsewhere, network redundancy linking an area to the wider system and generation fleet will often be used to provide sufficient security of supply.

Across these first three sets of tensions, when considering a particular intervention, the market designer needs to think about the impact of each objective, on each timescale, and for each area of the country. One principle that is often cited is 'cost reflectivity'. Many commentators argue that the purpose of locational signals, in common with other elements of electricity market design, is to make the commercial and regulatory framework cost reflective, and that this leads to an economically efficient, cost effective and, by implication, 'low cost' outcome overall. In GB, the argument is most regularly used in relation to network charges [36] where the long run investment cost reflectivity is often used. Locational marginal pricing is similarly argued to be reflective of short-run marginal costs [37]. However, it could create a barrier to delivery of low carbon generation capacity in the long term (creating a tension between objectives). It could also lead to higher costs for some groups of consumers (creating a tension between different places regarding a particular objective), and could delay investment in lower-cost generation (creating a tension between timescales).

A related set of tensions comes from the differences between ideal- and real-world outcomes. Many real-world influences distort or obstruct the influence of a locational signal, leading to a significant difference between theoretical modelling results and real-world outturn. For example, much economic modelling assumes perfect information sharing, rational decision making, and often perfect foresight. Such models are extremely useful for helping us to understand the theoretical dynamics of a system and the maximum potential impact of a particular reform. However, the breakdown of these assumptions in the real world can lead to very different outcomes.

Reform of BSUoS is a recent example where a theoretically cost reflective signal on both generation and demand was replaced by a purely cost-recovery-based approach, with charges only levied on demand, because of issues of practicality. Prior to 2023, system-wide BSUoS costs incurred during a single settlement period were recovered from generation and demand operating during that settlement period. This meant that market participants who could forecast when BSUoS costs were likely to be high might choose not to operate, and therefore not contribute to those BSUoS costs, to avoid high charges. However, on investigation, industry and Ofgem agreed it was unlikely that market participants could forecast BSUoS costs sufficiently far ahead to impact, practically, on operational decisions. It was concluded that, instead, they would likely be adding a risk premium to other revenue streams in order to cover the risk of facing high BSUoS during some periods. The result was that Ofgem agreed to change BSUoS charges, moving them to a fixed pound per MWh charge which remains constant for a period of six months. In effect, they abandoned the cost reflectivity principle, in light of evidence that whilst theoretically correct it was impractical.

To summarise: locational reform options should be directly linked to all three core objectives of the electricity system. Decisions should explicitly consider the tensions inherent within and between different objectives over different timescales and at different places. And real world effects also need to be considered. The outcome needs to be a balance, focused on exactly how the end goal will be achieved.

2.2.1 Locational signals for energy and for system services

Energy is the commodity traded across the electricity system, facilitated by the wholesale energy market itself. But the electricity system isn't only about energy. The commercial and regulatory framework also needs to deliver power 'capacity', that is the potential to generate, transmit and distribute energy at a particular rate, or to reduce the rate of use of energy during so-called 'stress events', either by moving the use of at least some of the energy to another time or foregoing the services gained from at least some of it. Capacity to produce power or reduce demand is procured through the capacity market. And, to operate, the system needs a range of 'system services' such as capacity to deliver frequency regulation and containment, reserve capacity, restoration services and other forms of flexibility. Then, sufficient network capacity is needed in order to access production capacity or system services.

Not only is it important to consider locational signals in the wholesale energy market itself, but it is also important to think about how each of these additional system services provided by network connectees are procured, and what locational signals are used as part of those services. Table 1 lists each of the commodities and services involved in the operation of the electricity system, and identifies why locational signals can be important in the procurement and delivery of each one.

There is one particular difference between energy and system services that is important to the context of locational signals. The energy market is a 'many-to-many' market with multiple generators selling to multiple commercial consumers (in the wholesale market usually represented by supply companies). However, for system services, there is a single buyer, in most cases NESO or government, and that buyer is also in charge of how the market is designed. Whether these services are procured through a market (such as the capacity market or the dynamic response markets), tender rounds (such as with many technical ancillary services), or regulatory rules (such as mandatory reactive power provision), NESO can choose the design in the way that best delivers its objectives.

Table 1: Summary of the importance of locational signals in energy and system services

Commodity or service	Number of 'buyers'	Why are locational signals important in its delivery?
Energy	Multiple commercial	Delivery of energy is the core purpose of the electricity system. Locational signals on the trading of energy can help align the generation, consumption and storage of energy with the physical constraints of the network. The demand-side of the market can usefully be exposed to locational incentives or requirements/prohibitions. However, these must remain aligned with the overall ambitions of the electricity system, including security and reliability of supply.
Capacity	Single (NESO on behalf of UK Government)	The Capacity Market buys reliable capacity capable of meeting demand during a system stress event. Providers must deliver their capacity during a system stress event, or face penalties. The need for capacity is currently assumed to be non-locational. For that assumption to be true, transmission network capacity needs to meet the standards set out in the SQSS to ensure that output from 'capacity' can be transported to demand during a stress event. In the future, the provision of capacity at particular locations may support more efficient transmission network designs. There is also potential value in geographical diversity in its own right, for example by minimising the risk of common cause failures such as extreme weather effects on infrastructure.
Constraint management	Single (NESO primarily through the BM)	NESO needs a locational mechanism in order to direct the redispatch of the market outcome in line with locational constraints, primarily transmission limits. That mechanism, the BM, provides an opportunity for some commercial assets to receive locational price and volume signals.
Inertia	Single (NESO)	Inertia is a core contributor to system stability. It plays a role in limiting the rate of change of frequency for a given imbalance. It also plays an important locational role in maintaining 'angle stability', ensuring inter-area synchronism in the event of a fault. The quantity of inertia required for a stable system depends on the operational strategy of NESO and can be increased or reduced by other operational decisions. There is not currently a national Inertia market or procurement process, but inertia is one service procured by regional 'Stability Pathfinder' tenders and the development of a stability market [38].
Frequency response (frequency regulation and containment)	Single (NESO)	Frequency response is the (generally automatic) change in generation/demand as the system frequency changes, reflecting an imbalance between supply and demand. Frequency response can be 'sterilised' if it is on the wrong side of a network constraint to the source of the supply/demand imbalance. There is therefore value in considering location when procuring frequency response. NESO has recently developed the Dynamic Response suite of services with procurement based on a day-ahead process. Currently, we understand there is no locational element in this.
Reserve	Single (NESO)	Reserve is the (generally manual) change in generation/demand to restore system frequency and replace the action of frequency response assets in the minutes and hours following a fault. As with frequency response, it can be neutralised if it is on the wrong side of a constraint and there is

Commodity or service	Number of 'buyers'	Why are locational signals important in its delivery?
		therefore value in considering location when procuring it. NESO has recently introduced the Balancing Reserve product, with procurement based on day-ahead auctions. However, we understand there is no locational element in this.
Reactive power (voltage management)	Single (NESO)	Reactive power is used to manage voltage and must be produced or consumed close to the location where voltage management is needed. Therefore, its procurement is inherently locational. NESO currently accesses reactive power through a combination of obligatory provision – generators are required to provide a certain level of reactive power capability through the Grid Code – and locational market-based procurement.
Restoration	Single (NESO)	Restoration, which includes services that used to be called 'black start' – is the ability to independently re-energise part of the system following a complete system collapse, or otherwise support re-energisation and the restoration of demand. The re-energisation relies on assets being available at different locations across the system. A certain number of restoration providers are needed in each region. Its procurement is inherently locational. Currently, NESO procures restoration services through a series of regional tender rounds.

2.3 Electricity system locational signals today

There is a wide range of cash flows, rules and mechanisms within the current electricity system commercial and regulatory framework. Understanding each of these, and the role that it plays – or does not – in delivering a locational signal to different types of asset is the first stage in developing a coherent strategy. Figure 5 shows the major cash flows which cover both the trading of energy via the wholesale energy market and each of the major system services.

Except for wholesale energy trading, all other services are procured through structures that involves a single buyer. However, in each case, the costs are passed onto a set of actors who ultimately pay for the services. With energy balancing costs, the settlement process distributes the costs to those 'parties' in the wholesale market who were out of balance. Parties can hold portfolios or single assets, so this includes individual generators, portfolios of generators and storage, or suppliers. The cost of the transmission network is passed on to a combination of both generators and demand through TNUoS. For other services, various mechanisms pass them to end consumers.

The structures which apply a meaningful direct locational signal are:

- TNUoS which provides a locational signal for generation and demand, which applies primarily on investment timescales. The locational signal to generation can be strong and is currently under debate, with Ofgem recently indicating that the current methodology may need to be changed to deliver net zero, noting in a recent open letter that "TNUoS charges are projected to increase significantly during this period, creating challenges for critical investment and reinvestment decisions being made in the next few years to reach a clean power system by 2030" [39]. The locational signal to demand is significantly weaker because the granularity at which it is averaged into zones is coarser and because it is floored at zero, meaning that demand TNUoS is essentially flat for northern England and the whole of Scotland[6].

- The Balancing Mechanism, as a 'pay-as-bid' process, pays different prices to different assets. In respect of actions to relieve energy balance, the price received is not a function of location, but rather of the price asset operators choose to bid. This may reflect the marginal cost of operation or it may reflect an estimate of what other bids will be accepted (where asset owners try to get accepted at just below the most expensive bid required. When resolving transmission constraints there is a locational volume signal because only assets in a particular location relative to the constraint can be accepted for downward balancing (curtailment of generation or increase in demand) behind an export constraint or upward balancing (turn-up of generation or decrease in demand) in front of an export constraint. There is also an interaction between the freedom of some assets in some situations to submit Bid prices to turn down generation through the Transmission Constraint Licence Condition (TCLC), a regulatory rule introduced to stop generators profiting from being turned down behind a transmission constraint.

  These characteristics – pay-as-bid and interaction with other regulator rules – reduce the ability of those assets to use the Balancing Mechanism as a route to make short-run operational profits to build a long-term investment case. The issue is discussed in more detail in Section 4.4.

- The tender processes for procurement of technical ancillary services and restoration are usually carried out regionally. This includes tender rounds for voltage support (also known as reactive power provision) and various stability issues. This means both the opportunity (volume) and price will vary by location.

In addition, there is a significant indirect signal set by the regulatory approach to the allocation of transmission system losses:

- Transmission Loss Factors (TLFs) are factors applied to market participants' metered volumes to adjust the total volume of energy traded to account for transmission losses. TLFs are locational and calculated to align with the estimated marginal average seasonal contribution of an asset to system losses. This means that generators that typically contribute to increased losses (e.g. by generating in areas that tend to export) receive TLFs less than

[6] There is a code modification, CMP440, currently under consideration to remove the floor at zero [91]. As discussed in Section 4.2 this could be an important part of increasing the locational signals on demand.

1 whilst generators that typically reduce losses (e.g. by generating in areas that tend to import) receive a TLF greater than 1. The same principle is applied to consumption. TLFs adjust the metered volume by multiplication before it is entered into settlement. The locational variation of TLFs can be significant, with differences across the country during winter rising to 5% or more. However, because they are fixed for a season (three months at a time) they do not provide an operational locational signal.

Table 2 summarises the direct and indirect locational signals faced by market participants in today's framework. This highlights that TLFs, TNUoS and ancillary service contracts can provide meaningful investment timescale locational signals. However, on operational timescales, it is only the BM, where actions are bought to relieve network constraints, and the procurement of certain technical ancillary services that provide operational timescale locational signals in today's market. Whether these present-day operational signals are sufficient to ensure optimal utilisation of resources is open to question.

An important exception to the set of locational signals that are present in the current framework are interconnectors. These assets are exempted from TNUoS, BSUoS and adjustment by Transmission Loss Factors. Historically, this has been to comply with EU regulations which consider interconnectors as cross-border network capacity rather than energy market participants (see section 3.3 for a fuller discussion). Since Brexit, these exemptions have been retained through the Trade and Cooperation Agreement. In addition, whilst market participants who trade across interconnectors are Balancing Mechanism Units, they are unable to participate in day-to-day BM activity because of the lack of cross-border balancing-timescale arrangements between GB and the EU.

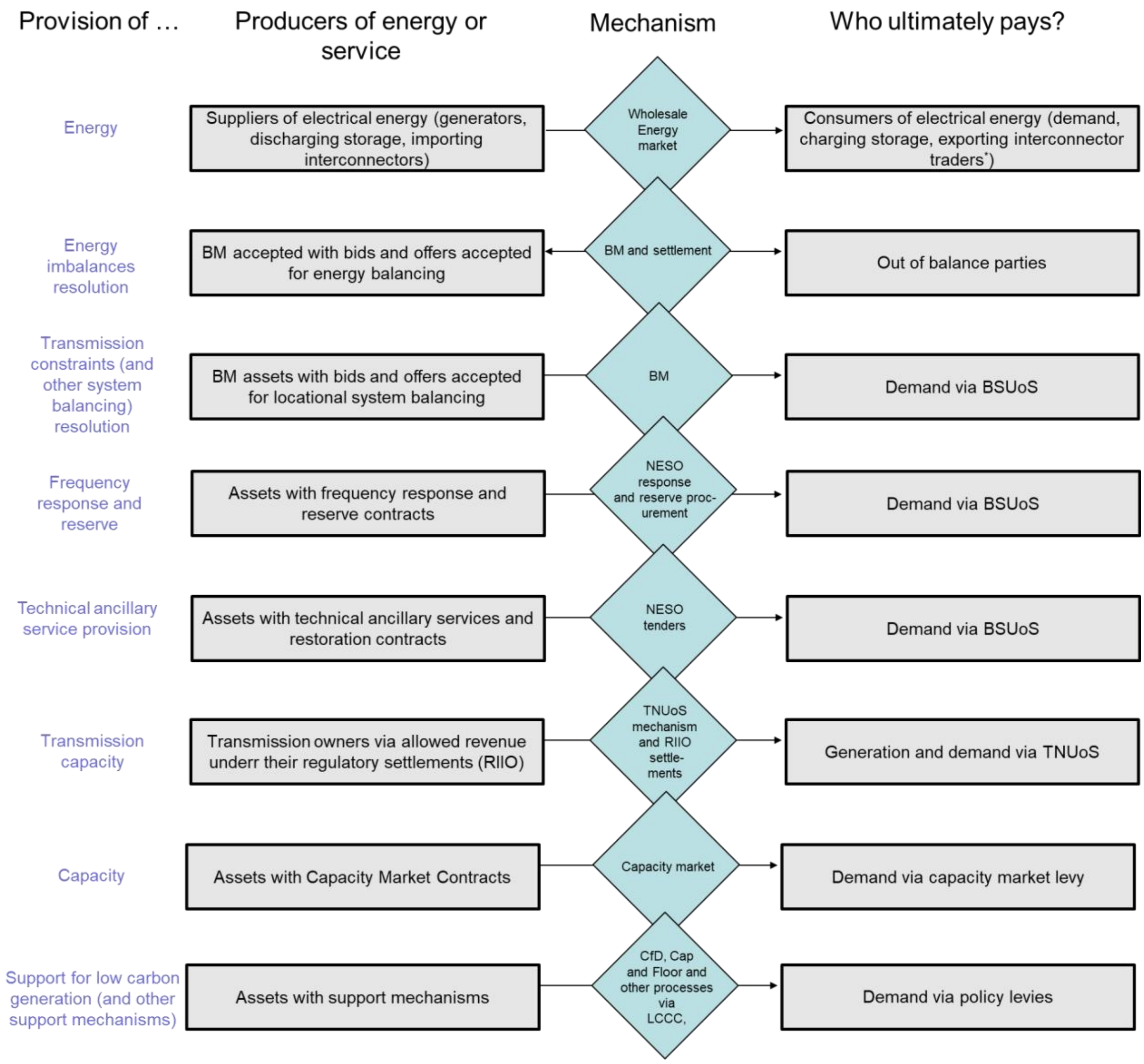

Figure 5: Major cash flows in the current GB electricity system commercial and regulatory framework. Cash flows identify who sells either energy or system services, the mechanism involved in its procurement and who ultimately pays.

Table 2: Locational signals in the current electricity system commercial and regulatory framework

Structure	Direct locational signals	Indirect locational signal	Locational signals on investment timescales?	Locational signals on operation timescales for market participants?
Wholesale energy market	None/Very limited	Transmission Loss Factor (TLF) introduce a zonal volume-based signal varying by season. Locational signals from outside the electricity system commercial and regulatory framework will be particularly important. For example, for generators of all types, the costs of energy production will introduce locational signals, e.g. average wind speeds or cost of access to fuels.	Yes, via expectations for TLFs	None/Very limited
Balancing Mechanism	Pay-as-bid design reduces the locational market 'price' signal compared with pay-as-clear, particularly for actions on generators behind a constraint affected by the Transmission Constraint License Condition (TCLC). The Balancing Mechanism's role in managing transmission constraints means greater volumes of Bids and Offers required in different locations, introducing a volume impact.	LTFs adjust volumes on a locational, seasonally varying basis. Non-generators behind a constraint and all generators in front of an export constraint can attempt to guess the marginal required Bid Offer price (which will vary by location) and place their Bids/Offers just below.	Some potential, but severely limited by pay-as-bid design and interaction with regulatory rules.	Strong signals via the Balancing Mechanism
Capacity Market	None/Very limited	None/Very limited	None/Very limited	None/Very limited

Structure	Direct locational signals	Indirect locational signal	Locational signals on investment timescales?	Locational signals on operation timescales for market participants?
Ancillary service markets: Response and Reserve (R&R)	None through new dynamic services or balancing reserve (potentially some through legacy products. R&R increasingly procured via day-ahead national auction)	None through new dynamic services or balancing reserve (potentially some through legacy products. R&R increasingly procured via day-ahead national auction)	None/Very limited	None/Very limited
Ancillary services markets: technical services (stability, inertia, voltage support, fault current)	Typically, strong price and volume signals because of location-specific tender rounds, but locational signals are service specific.		Yes, where investment is underpinned by long-term technical AS contracts	Yes, where assets are dispatched in line with technical ancillary services contracts
Regulated charges (Connection charges, TNUoS, BSUoS, policy levies)	Connection charge: yes, there are strong investment locational signals, but these are related to local grid connection, not to national supply/demand/network balance. TNUoS: yes, strong locational price signal on generation with large uncertainty on level of future charges, much smaller locational signal on demand. BSUoS and policy levies: no		Yes, nationally through TNUoS and locally through connection charges	None/Very limited
Support Mechanisms: CfD, Dispatchable power Agreement (DPA), storage Cap and Floor,	No	CfD DPA: Volume adjusted by TLFs DPA, C&F, HPBM, Nuclear RAB: contracts currently set administratively through negotiation between government/regulator and the project. Therefore, there	No for CfD, yes for some others, but these tend to be through bespoke bilateral negotiations	None/Very limited

Structure	Direct locational signals	Indirect locational signal	Locational signals on investment timescales?	Locational signals on operation timescales for market participants?
Hydrogen production business model, Nuclear RAB		is scope for individual settlements to reflect locational costs and revenues (e.g. Nuclear RAB proposal for Sizewell C treats regulated charges as a 'pass through' element).	at a project level.	
Interconnector arrangements (How do they differ from those for other market participants?)	TNUoS and transmission losses are not applied to interconnector imports or exports, reducing the investment timescale locational signals compared with other market participants. And although market participants are BMUs they do not participate in BM activity. Interconnectors can and do participate in the provision of some technical ancillary service and restoration provision and receive the same locational signals as other market participants for these assets.		Locational signals through connection charges, and regulatory approval process	None/Very limited

2.3.1 Non-financial and non-electricity system locational signals

As discussed in Section 2.1.1, it is important to consider locational signals that come from outside the electricity system when reviewing options for changing the locational signals within it. The two sets can either reinforce each other or counteract each other Table 2 lists the key non-electricity system locational signals and important locational signals that may come from within the electricity system but are non-financial in nature.

Variable renewable assets provide an example of the effects of these classes of signal. There are strong locational signals from outside the electricity system. In particular, renewable resources vary strongly by location: wind tends to be strongest in the north and offshore, solar resource strongest towards the south. This sends a strong locational investment signal, with developers looking for locations which maximise potential capacity factors. It also sends a very strong operational signal: generation is only possible when the wind blows or the sun shines. This obvious point is rarely highlighted in the debate about locational pricing. However, the implication is that, for a significant majority of generation capacity, there are limited operational decisions to make. As discussed below, this makes it more urgent to explore, in greater detail, the role of locational signals in relation to flexibility.

Variable renewables face additional non-electricity system locational signal. For onshore wind, until summer 2024, there has been a strong signal from the planning system that has precluded significant development in England. For offshore wind, the areas included within seabed bidding rounds form another important signal[7]. And broader issues of public support, which can vary across the country, can hinder or help the development of projects. Finally, renewables, along with most new assets, face a challenge getting connected. There are well-known issues with the connection queue, with lead times of a decade or more for projects to get connection. NESO has been leading a programme of reform which has generated code modifications to allow improved management. Most recently, they indicated that there could be a role in queue management in delivering the generation mix, including technology, capacity and location, required by Clean Power 2030 [40].

Other asset classes also face important non-electricity system locational signals. Planning and consenting policy can impact on many developments and many assets face geographical constraints or incentives. An important class is flexible demand. For these assets, electricity forms an input into a much wider business case, and many of the investment and operational decisions depend on the locational demand for their products. The location of factories relative to their output market, and variations in the market for different outputs, represent significant considerations which can have important locational components.

Table 3: Non electricity system and non-financial locational signals on different asset types

Asset class	Non electricity system locational signals	Electricity system non-financial locational signals
Variable renewables	• Average annual renewable resources (investment) • Planning and consenting policy (investment) • Public opposition and support • Current renewable resource (operational)	• Grid connection dates (investment)

[7] This is listed as an electricity system non-financial signal. It is debatable whether seabed leasing is part of the electricity system or not. It is considered outside of REMA's scope. However, it is clearly developed as part of the development of the electricity system itself. It is also important to note that within areas identified for leasing there is also a financial signal reflected in the clearing price for leasing auctions.

Asset class	Non electricity system locational signals	Electricity system non-financial locational signals
	• Crown Estate and Crown Estate Scotland leasing rounds (investment)	
Schedulable power stations	• Planning and consenting policy (investment) • Public opposition and support • Access to fuel (investment/operational)	• Grid connection dates (investment)
Energy storage (batteries)	• Planning and consenting policy (investment) • Public opposition and support	• Grid connection dates (investment) • Non-firm grid connection rules (operation)
Energy storage (pumped storage and other medium to long duration)	• Planning and consenting policy (investment) • Geographical suitability	• Grid connection dates (investment)
Flexible demand (EVs, heat, industrial demand and hydrogen electrolysis))	• Differences in EV use patterns between rural and urban areas (investment/operation) • Difference in heat demand (e.g. higher demand in north (investment/operation) • Differences in characteristics building stock (investment/operation) • Regional and devolved policy drivers for electrification of transport, heat and industry (investment) • Locational factors related to the production of industrial electricity use (investment/operation) • Locational factors related to the distribution, storage and use of hydrogen for electrolysis (investment/operation) • Local or regional economic development planning (investment)	• Grid connection dates, particularly for large new connections or upgrades to peak power capacity (investment) • Distribution-level access rights and flexibility markets (investment/operation)
Interconnectors	• Planning and consenting policy (investment) • Geographical proximity to connecting market (investment)	• Regulatory process for Cap and Floor support (investment) • Net Transfer Capacity (NTC) restrictions (operation)

2.4 Locational signals across asset types

The different cash flows shown in Figure 5 highlight that there are many ways for assets to build a business case. Renewable business cases are based on the combination of the wholesale energy market and support mechanism payments (whilst relying on the balancing mechanism to replace any lost support mechanism payments if curtailed). By contrast, schedulable generation, particularly peaking power stations, will rely on a broader mix of revenue from the wholesale energy market, capacity market, ancillary services markets and directly from Balancing Mechanism actions. Similarly, energy storage, demand flexibility, nuclear power and interconnectors will all build business cases from different combinations of revenue stream.

This means that, when reviewing options for locational signals, it is important to consider how each option will affect different asset types.

An extreme example is a synchronous compensator whose role is to provide inertia, short circuit current and reactive power to support system stability. The role of synchronous compensators is not to generate energy and, therefore, signals of any kind limited to the energy market do not affect its investment or operation. If NESO wants to influence investment in and operation of synchronous compensators, it needs to do so through markets or regulatory cash flow based on the system services it does provide. Today, the maturing stability market is moving towards a nationally coordinated locational market, including long-term contracts offering contracts of up to ten years or more with four-year lead times[8].

Whilst synchronous compensators are an extreme case, a growing number of assets will use a mix of energy and non-energy revenue. This includes energy storage assets, schedulable power stations and flexible demand investments:

- **Energy Storage:** Ancillary services and balancing mechanism revenue streams play a significant role in battery and other energy storage business cases as well as energy market arbitrage. The capacity market is also important for longer duration assets. The balance between different revenue streams will change over time. Modo Energy estimates that in June 2024 battery revenues were around 20% from the capacity market, 25% from frequency response, 35% from wholesale trading, 20% from the Balancing Mechanism, and a minor amount from balancing reserve. (For comparison, a year earlier, Modo estimated that the wholesale trading component was less than 10%) [41].
  - **Peaking low-carbon schedulable power stations:** the growth of variable renewables means that a large fraction of GB electrical energy demand will be met from wind and solar in a net zero electricity system. In the 2024 FES pathways, wind and solar generate between 73% and 81% of the total GB generation output by 2035. Some schedulable power stations may continue to run as ‘mid-merit’ with running hours in the low thousands of hours a year. But significant capacity may need to remain operational with very low load factors acting as a backup for periods of low wind and solar output. For these plants, business cases are likely to depend significantly on capacity market and ancillary service revenue.
  - **Flexible demand:** There is no practical locational revenue stream for flexible demand today[9]. Without a locational energy market signal, some form of locational redispatch (e.g. improved Balancing Mechanism or pre-gate closure

[8] See recommendations of the Stability Market Design project [71] and description of future stability market within the NESO market’s roadmap [48].

[9] Locational BM revenue streams exist in theory but in practice are rarely used by the demand side.

constraint market) is required.

The asset types discussed above fit into the broader category of flexibility. The second REMA consultation defines flexibility to include schedulable low carbon power stations, reflecting the fact that its role will shift towards one of long-duration flexibility provision. The locational question for flexibility has a very different context than that for generation or demand. One reason is that flexibility is a more complex concept to model, and under the banner of 'flexibility' there are a wide range of asset types, capabilities and approaches to operation. Flexible assets include flexible generation, various types of flexible demand, energy storage, and interconnectors. And the dimensions of flexibility include agility, Schedulability, and persistence (see Section 1.6 in reference [9] for a full discussion). It is, therefore, difficult to give a general answer to the question 'what locational signals should flexibility face?'

However, it is an important question. One challenge to the implementation of locational wholesale pricing is that the characteristics of renewable generation – the non-financial locational signals it faces from outside the electricity system such as the strength of wind resource, and the variability and intermittency of their nature – constraints the ability of financial incentives or rules to affect operation. In effect, additional signals can only limit generation below what is possible with the prevailing wind or solar resource. There is no option to *increase* generation when the wind isn't blowing or the sun isn't shining. In addition, much demand will continue to be met in a relatively inflexible way. This means that there will be a strong reliance on flexibility assets to actually respond to locational signals.

To summarise the current situation for electricity system locational signals:

- Generation and storage assets face a strong but uncertain locational investment signal through TNUoS and Transmission Loss Factors (TLFs)[10].
- Other assets face limited locational investment signals.
- The locational operational signals faced by all assets are weak and indirect, except for some technical ancillary services.
- Interactions between support mechanisms and other frameworks in the electricity system can dampen or remove locational signals.
- For assets other than variable renewables, system service revenue streams are likely to be a factor in investment and operational decisions. The reliance will vary by asset class and over time. For energy storage as an example, ancillary service revenue was significant in 2022, but is less significant now as some markets for frequency response appear to have saturated, leading to a collapse in prices. However, considering reform options that deliver locational signals through routes outside the wholesale market has the potential to influence most asset types capable of delivering flexibility.

[10] Storage is charged generation TNUoS as it is formally categorised as a generator by the electricity licencing framework. It may also face demand TNUoS through the Embedded Export Tariff. However, this the EET is charged based on triad export and can (relatively) easily be avoided in areas of the country when it might be significant.

- The Balancing Mechanism is a central tool for management of flexibility, but its pay-as-bid format means the locational price signal is weaker than it would be if using marginal pricing. This is exacerbated by additional rules, such as the TCLC on generators and by IT and operational processes used by the ESO control room.
- Interconnectors are a special case and require their own consideration.

2.5 Locational signals and strategic planning

System development has previously been ‘market driven’, at least in theory, with network planning aiming to ‘follow the market’. The move to a more strategically planned system means that system development will be more centrally planned in the future. If the government is serious about the plan being implemented, the role of market and regulation in the future needs to be aligned with delivering the plan. In fact, a key outstanding question is what approaches will be used to deliver strategic spatial plans?

The commercial and regulatory framework will itself be an important part of delivering strategic plans. For example, NESO’s Clean Power 2030 advice suggests that, alongside wider planning and consenting, the rules for management of the connection queue will be used to deliver that plan. If this means that connections of a particular technology in particular locational will be prioritised, that creates a very strong, rule-based, locational investment signal.

This shows the importance of co-developing strategic planning approaches with the wider reform of commercial and regulatory frameworks. It will be important to avoid outcomes REMA reforms implanting changes which then create barriers to delivering the strategic plans.

Initially, that means considering reform options against their ability to deliver Clean Power 2030, and in the longer term against the SSEP. Individual interventions could support the delivery of some elements of a strategic plan and create barriers in others. The choice will often need to balance competing effects. For example, Clean Power 2030 and SSEP are likely to be based on pathways with significant quantities of new renewable generation in Scotland. They will also likely depend on new (flexible) demand in Scotland to support efficient use of those renewables. Using TNUoS as an example, in this context, a cost reflective signal applied to both generation and demand could:

- **Create a locational signal reinforcing the strategic plan’s view of demand distribution** through strong locational incentives on demand to locate in Scotland, delivered by negative TNUoS demand side charges (in a scenario where the current floor at zero is removed).
- **Create a locational signal working against the strategic plan’s view of renewable generation distribution** through strong locational generation TNUoS, which disincentivises generation in Scotland. This could be ‘cost reflective’ of long run transmission investment costs but, as an additional cost

to generation in the north compared with the south, work against the strategic plan and would require additional mechanisms to ensure that developers could locate new wind farms in Scotland and overcome that high TNUoS charges.

These highlight another tension to add to those discussed in Section 2.2. A strategic plan itself can be thought of as a locational signal, although whether it can be regarded as an incentive, rule or mechanism will depend on the levers used by Government, Ofgem or NESO to ensure implementation of the plan. A strategic plan will only be delivered through arrangements that are put in place to deliver it. For example, a strategic plan will only deliver additional or accelerated capacity of renewables in Scotland if some or all of planning, consenting, seabed leasing, connection policy and queue management, CfD allocation and design, TNUoS charges and transmission loss factors, add up to deliver signals which will deliver it.

This suggests that one useful principle is that locational signals should, where possible, align with the delivery of the strategic plan. This does not have to be an absolute principle, rather one that continues to be balanced against other considerations.

2.6 Clean Power 2030

In October 2024, NESO published their Clean Power 2030 advice, which suggests that achieving clean power by the end of this decade[11] is feasible, if challenging. The document presents two pathways to achieving clean power: 'new dispatch' and 'further flex and renewables'.

UK Government will review the advice and is expected to adopt an approach to delivery by early 2025. At that point, Clean Power 2030 becomes a strategic plan for the rest of the decade, and will be followed by the SSEP (due in 2026) [42]. The Clean Power 2030 analysis includes a breakdown of generation capacity by region and spatial estimates of transmission constraints (see annex 2 and additional data tables). As such, it goes beyond analysis typically published in FES and begins to set expectations for the spatial development of the energy system.

The advice also identifies critical enablers for delivering clean power in 2030, including electricity markets and investment, connection reform and development of the NESO itself. There are also several areas that fall outside the electricity system commercial and regulatory framework, such as supply chains, planning and consenting. It highlights many of the issues discussed in this report and starts to consider how these can be used to shape the future power system. However, these discussions remain at a relatively high level this early in the Clean Power 2030 process.

The advice also discusses transmission investment, noting that current plans must be accelerated to deliver more capacity by 2030. It concludes that three additional

[11] For the purposes of NESO's work, clean power was defined as: "by 2030, clean sources produce at least as much power as Great Britain consumes in total and unabated gas should provide less than 5% of Great Britain's generation in a typical weather year" [2].

projects, beyond those already expected to be commissioned by 2030, need to be accelerated, and there is the potential to accelerate another six. The analysis suggests that constraint costs in 2030 would fall significantly if this is achieved: from £7.8 billion under current network development plans, to £3.6 billion with the three ‘required’ projects commissioned, and down to £1.9 billion with the additional ‘possible’ projects commissioned. Delivering additional links will be challenging, and it is not just a matter of costs – there are significant practical issues associated with developing new transmission capacity. These include supply chains, public acceptability and availability of sufficient technical expertise.

The reform of current arrangements to introduce further locational signals to the commercial and regulatory framework needs to be carried out in this context: NESO’s Clean Power 2030 advice creates the first outline strategic spatial plan for the electricity system. It acknowledges that market and regulatory reform, including locational elements, is one of the important enablers, and it is aware that the financial value of these reforms will be influenced by our ability or not to deliver sufficient network capacity.

2.7 Part 2 conclusion: rearticulating the locational challenge

Locational signals, including incentives, rules and mechanisms which can affect market dispatch and redispatch options from NESO, including those delivered on both investment and operational timescales, need to be designed to support delivery of our overall system objectives of minimising cost, ensuring a secure supply, and delivering a decarbonised electricity system. They should reflect the inherent tensions between and within these objectives on different timescales. And as strategic spatial energy planning becomes more established in the development of the electricity system, locational signals as a whole should be designed in a way that supports its delivery, even where they do not directly align.

Prior to gate closure for the Balancing Mechanism, operational locational signals in the GB electricity system commercial and regulatory framework are widely regarded as weak at best. This leads to the need for significant volumes of redispatch where the outcome of the wholesale energy market is not aligned with system limits, including both transmission network constraints and overall energy balance. The objective isn’t to reduce curtailment to zero, rather to find and deliver the optimal balance between curtailment, flexibility provision and transmission investment. This is the ‘locational energy challenge’.

In addition, there are likely to be growing locational issues associated with the delivery of other system services, including ‘capacity’, ancillary services and restoration. This is the ‘locational system services challenge’.

Both challenges are intimately linked to the development of the transmission system. New transmission capacity is often able to relax locational constraints on the supply of and demand for energy and on the provision of system services. Therefore, there is an additional challenge, 'the transmission network challenge', which is currently beyond the scope of REMA, but affects it. Ultimately, the objective is to minimise total costs across all three aspects – energy, system services, and transmission – across both investment and operational timescales whilst aiming to deliver the most appropriate balance of a wider set of societal objectives.

The impact of any set of locational signals will vary across different asset types, particularly given the growing specialisation in service provision. Market reform needs to consider the impact of locational signals on different asset types: e.g. variable renewables whose revenue is almost entirely related to energy markets hedged by CfD support and curtailment payments; schedulable generators which mix energy revenue with Capacity Market and ancillary service revenues; and battery storage, which combines wholesale arbitrage, Balancing Mechanism revenue, Capacity Market contracts and ancillary service provision.

2.7.1 The energy challenge

The energy challenge has two elements: 1) how to reduce the volumes of redispatch actions; and 2) how to ensure that redispatch actions are implemented cost-effectively. Failure to address either could lead to a total cost of redispatch that might be regarded as excessive.

The solution to this challenge will need to consider locational signals on market participants across the full range of commercial, regulatory and policy frameworks to which they are exposed, as well as any locational influences beyond the electricity system. It is likely to include both incentives on market participants to operate in particular ways, and rules and mechanisms which allow NESO to influence what operates and when. It is important that the scope over which locational signals are considered is not set too narrowly.

The ability to dispatch or redispatch the system effectively depends in part on operational-timescale locational signals, but also on the aggregate effect of investment-timescale locational signals. This affects which assets are built and therefore available for (re)dispatch and where they are. For this reason, in the medium to long term, it is not possible to consider the (re)dispatch question without reference to investment-timescale signals. It is also important to note that, over time, the volume of non-locational energy-balance related curtailment will become comparable with, or even exceed, the volume of locational network constraint-based curtailment.

Market and regulatory reform, including the articulation of locational signals, needs to consider delivering net zero quickly whilst ensuring energy is supplied at the lowest cost with sufficient resilience.

Solving these challenges whilst maintaining a national wholesale market means either providing incentives for market participants to align their energy dispatch with system limits outside of that market, improving the ability of NESO to constrain the initial dispatch, changing the rules under which they operate, or providing improved mechanisms for NESO to redispatch the market. It also depends on finding ways to incentivise the right assets to locate in the right places – a challenge which links back to investment-timescale signals.

2.7.2 The system services challenge

There are also locational challenges associated with ensuring that the provision of other services – capacity, response and reserve, other, technical ancillary services and restoration – are in line with system needs. The scale of these challenges in financial terms is smaller than that of the energy challenge. However, there are examples of system services where their procurement, currently on a non-locational basis, is at odds with the physical limits of the system. The scale of the challenge today is hard to define, but it might reasonably be expected to grow as the scale of system service requirements grows along with the number and type of providers and the prevalence of transmission constraints.

2.7.3 The transmission investment challenge

The scale of each of the above challenges is highly dependent on the development of the transmission network. Greater transmission capacity will reduce the scale of the locational energy and system services challenge but at the cost of the investment needed to provide that network capacity. More network will reduce the need to constrain off renewables and replace it with more expensive generation elsewhere. These issues must continue to be addressed together.

2.7.4 Delivering the strategic spatial plan

Since privatisation, system development has been largely market driven. However, both the current and previous UK Governments have expressed a strong desire for strategic spatial energy system planning. The publication of NESO’s Clean Power 2030 advice represents the first stage of strategic planning, one focused on delivering clean electricity by the end of this decade. Clean Power 2030, or any other strategic spatial plan, only has value if it can be delivered. Market and regulatory arrangements should support the delivery of Clean Power 2030 and later the SSEP. In fact, they should be part of the strategic plan as they represent key levers which can be used to deliver the plan.

3 Reform options

This section discusses potential reform options, both individually, and in groups. It covers the different types of locational signals discussed above, including incentives, rules and mechanisms. And it covers options to improve the initial energy market dispatch, the ability for the NESO to redispatch the market, and options which provide locational signals for the provision of system services.

The factor that remains constant throughout is a national wholesale energy price. However, the reforms discussed include removal of firm access rights, which can introduce a locational volume signal into wholesale energy trading and into other commercial and regulatory mechanisms. It also includes options for using central dispatch alongside a national price.

3.1 Reform options for the locational energy challenge

There are two routes to improve operational dispatch: place better incentives on market participants so that, through their own internal decision making, the initial energy market dispatch is better aligned with system limits; or to provide NESO with better tools for influencing either the dispatch itself or the redispatch.

Figure 6 shows one way to characterise the interventions that can be made. The left-hand branch of the chart shows options for incentivising market participants, the right-hand branch shows improved mechanisms for NESO. Within the category of better mechanisms, there are two subcategories: mechanisms to improve the initial market dispatch itself and mechanisms to support redispatch.

It is important to remember that different reforms might include multiple options either by explicitly including a package, or because the introduction of one particular mechanism can include options from different strands. For example, locational marginal pricing implies both a locational price signal, which is an incentive on market participants and potentially a loss of firm access rights, which is a mechanism allowing NESO to avoid paying for curtailment.

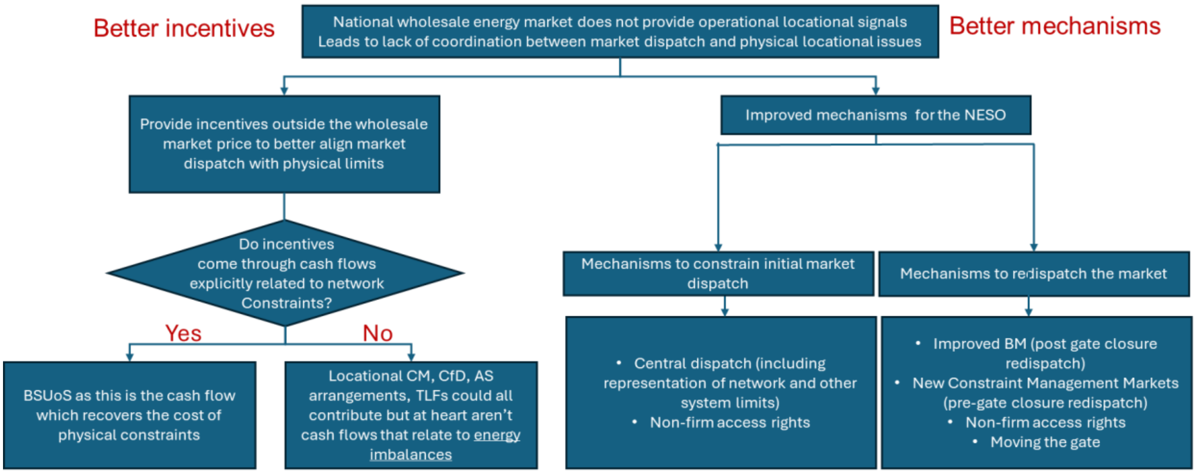

Figure 6: Summary of options for locational signals to improve any dispatch

3.1.1 Better incentives on market participants

The option to introduce locational wholesale energy prices, which is not considered in this report, falls under the category of better incentives on market participants. Locational pricing is an intervention that has a direct causative cost-reflective argument, at least in theory, to support it. It means that prices paid by demand and to generation reflect, subject to some potentially significant simplifications, the short-run marginal cost of meeting demand at a particular place on the system at a particular time. It is, potentially at least, a cost reflective reform.

Within the scope of this review, the use of incentives requires looking at other cash flows. There is one other that could deliver a directly cost reflective approach to issues such as transmission constraints: BSUoS. This is used to recover the costs incurred by NESO in balancing the system and resolving transmission constraints. As such, if BSUoS could be recovered in a way that aligns the charges with those who contributed to causing power flows to reach or exceed network limits without NESO action, it could deliver a directly cost-reflective charging structure with the potential to encourage market participants to internalise the cost of constraints into their operational decisions. However, there are significant concerns with any attempt to deliver a practical as well as theoretically cost-reflective BSUoS signal. A recent industry and regulatory review concluded that the practical difficulties outweighed the theoretical value and moved BSUoS from a partially cost reflective (although non-locational) charge to a purely cost-recovery based cash flow.

The remaining alternatives to wholesale pricing and BSUoS are to use another regulatory cash flow, such as the Capacity Market, CfD or ancillary services. These could include either the payments made to providers of each of these services, or through the levies or charges used to recover the costs of these schemes. Another related option is to use the allocation of transmission losses.

For any of these options, when specifically considering energy market dispatch or redispatch, locational charges would not be tied directly, in a cost reflective way, to constraint costs. At best, there may be opportunities to use closely correlated incentives rather than incentives that are causally tied to the transmission costs themselves.

The most promising option would be to use the allocation of transmission losses, as the current makeup of the GB electricity system is likely to show a correlation between losses and transmission constraints. Generators in the north of GB tend to contribute more to transmission losses because their power often needs to flow further, through a greater electrical resistance, than generation closer to the south of England. These generators also currently tend to contribute to transmission constraints, therefore a stronger operational-timescale signal delivered through dynamic transmission loss factors may provide a signal that incentivises these generators to avoid operating in ways that exacerbate constraints. However, it is also possible to imagine a situation where transmission losses do not directly align with constraints – for example, where interconnectors connected in south east England drive constraints in the south of England without significant contribution to transmission losses.

3.1.2 TNUoS: an example of the trade-offs between cost reflectivity and net zero

TNUoS has long been designed to deliver a long-run cost-reflective signal on investment in assets connecting to the electricity system. In an open letter published in September 2023 [43], Ofgem identified five principles which inform their development of the TNUoS methodology. The first was cost-reflectivity. Whilst the open letter discussed the importance of balancing the different principles, and acknowledged that there could be trade-offs, the position outlined reiterated cost-reflectivity as central to the way TNUoS is designed, ensuring that an asset's impact on transmission investment costs is internalised into its own investment decision.

However, a year later, in September 2024, Ofgem recommended that "a temporary Cap and Floor on wider TNUoS charges for generation would offer the most efficient type of intervention". This was driven by a desire to ensure that the required pace and timing of generation investment to meet our 2030 goals "is not compromised by the TNUoS regime." [39]

The 2024 letter suggests there is a growing tension between cost-reflectivity in TNUoS and the ability to deliver clean power or net zero. As well as the specific recommendation, Ofgem also discussed the role of TNUoS and its potential to change significantly as the UK Government brings forward strategic spatial plans focused on delivery of net zero.

The suggestion, in this case, of a solution that is likely to curb cost-reflectivity is an example of the trade-offs between two principles represents required in market reform. It points to the importance of not treating principles such as 'cost reflectivity' or 'lowest cost' as isolated outcomes, but as parts of a wider overarching framework where differing objectives, principles and timescales need to balance.

3.1.3 Improved mechanisms for NESO: central dispatch[12]

Within the category of improved mechanisms for NESO, there are two further categories. The first is mechanisms which allow NESO to influence the initial market dispatch, even where there are no strong incentives on market participants. A move from a self-dispatched to a centrally dispatched market would provide significantly greater opportunity for NESO to control the energy market dispatch itself. The degree of control would depend on several design decisions, such as the inclusion of so called 'self commitment' [44], and on how central dispatch is combined with other options. Central dispatch is often combined with locational pricing, and with the loss of firm access rights, but it is important to separate the effects of each part of the reform.

As an example of the impact of central dispatch, we consider a version which includes mandatory participation in a day-ahead, asset-level auction in which the dispatch algorithm includes a network model. This would allow NESO, acting as the Market Operator, to align day-ahead market dispatch with physical system limits and have visibility and confidence over that dispatch. This is in contrast to the current system of non-binding Initial Physical Notifications (IPN) which market participants are currently required to submit at day-ahead stage for individual assets.

There would still be a need for further adjustments, either through intraday market dispatch or a post-gate closure balancing mechanism. Intraday auctions would allow NESO to adjust the market dispatch to reflect changes in the forecast of renewable output and demand and the availability of plant because of faults after the day-ahead dispatch. An adjusted balancing mechanism would effectively continue this process in real time.

By optimising the utilisation and scheduling of assets across the whole electricity system rather than, as in self-dispatch, relying on each market participant to optimise its own portfolio of assets in isolation from those of other actors, central dispatch can help reduce the volume of redispatch actions that need to be taken through any balancing mechanism and provide greater certainty over the physical feasibility of the market outcome.

However, central dispatch on its own does not deal with the current issue of redispatch costs. Market participants currently benefit financially from firm access rights. This allows them to trade energy with any other market participant without consideration of the relative location of generation and consumption even when the system cannot physically accommodate those flows. Market participants – which in this context primarily means generation, but can also mean flexible demand such as that provided by batteries in charging mode – are reimbursed lost revenue through accepted Bids in the BM which are, in effect, curtailment payments. There is an implicit assumption that competition in the market will drive dispatch towards the lowest-cost set of generation across the whole system.

[12] The 2024 REMA Autumn Update [92] laid out a minded to position that: "We are not minded to take forward centralised dispatch under either reformed national pricing or zonal pricing at this stage, but are open to considering the evidence that the NESO are gathering on it."

The equivalent of firm financial access rights under a mandatory central dispatch system would mean that assets that were notionally ‘in-merit’ in the centralised auctions, but were not dispatched because of system constraints, would still need to be reimbursed. This would simply move the current set of constraint payments into a different mechanism.

Therefore, although central dispatch may reduce redispatch needs and may also provide a more efficient route to the final operational pattern of the system, it would be decisions on financial access rights which will affect much of the cost that currently sits within the basket of redispatch (constraint) costs.

There are a range of models for central dispatch, and if implemented, the details of the particular model chosen would be important. For example, there is significant uncertainty in whether self-commitment would be allowed and what the status of self-commitment would be in the face of network constraints. For example, where self-commitment is allowed, there is a risk that self-committing assets lead, on their own, to a network constraint. This would have failed to solve the original issue and a further mechanism would still be required to relieve the transmission constraint. By contrast, a central dispatch model without self-commitment and combined with non-firm access rights would allow the NESO to dispatch inline with network limits without a financial cost. The two models would have significantly different consequences for project finance and for contractual arrangements.

3.1.4 Improved mechanisms for NESO: non-firm access rights[13]

The impact of removing firm access rights is to change the financial relationship between NESO and market participants. With firm financial access rights, whilst market participants may physically respond to requests to change their output, NESO are obliged to reimburse them for doing so. Without firm access rights, the need for NESO to reimburse is removed. An obligation to physically respond to instructions from NESO may also need to be introduced.

Therefore, whilst central dispatch tackles the technical challenges of aligning market dispatch with system limits, removing firm access rights can remove the direct cost of doing so (See Box 2, for further discussion of the potential consequences).

Theoretically, all four combinations of self and central dispatch, along with firm and non-firm financial access rights, can be realised. The current system combines self-dispatch with firm financial access. As far as we are aware, all existing models of locational marginal pricing implemented in other markets combine central-dispatch with non-firm access. Figure 7 describes how each of the combinations could operate and what the impact might be on NESO costs and operation and on market participants.

[13] The 2024 REMA Autumn Update [92] laid out a minded to position that: “we are no longer considering reforms to transmission network access rights for new generators under reformed national pricing. This is due to concerns that introducing non-firm access rights for these assets could lead to operational inefficiencies and would only provide an incomplete locational signal.”

Figure 7 summarises the impact that different combinations of self and central dispatch and firm and non-firm financial access rights could have.

A further area where non-firm access rights could be important is in relation to energy storage. Under firm access arrangements, batteries and other storage assets have to be able to access the system, at least financially, at all times up to their installed capacity as both a generator and a demand. This is despite the fact that there are clear circumstances where, with effective market arrangements, batteries should not be incentivised to consume and other circumstances where they should not be incentivised to produce. Their connection can take up local substation and circuit capacity at the expense of other assets, such as renewable generators, even though their operation could well be anti-correlated with the availability of renewables. Similarly, there has historically been a risk that both transmission charging and wider network planning uses inappropriate assumptions about the correlation of battery and renewable operation.

Non-firm access rights for energy storage under a reformed national market could lead to a more effective system design by providing transmission owners and the NESO with confidence that the operation of batteries could be curtailed at zero cost under specified circumstances. This may not have an unduly negative impact on battery finances, as long as the conditions under which curtailment could be applied, aligned with periods where the battery would not be incentivised to generate (for export access rights) or consume (for import access rights).

3.1.5 Other tools to improve redispatch

Three other mechanisms for the improvement of redispatch are considered. These are a) continue to make improvements to the Balancing Mechanism through which post-gate closure redispatch is done; b) the development of constraint management markets which could run alongside the wholesale energy market pre-gate closure; and c) change the timing of the gate.

Significant progress is being made on improvements to the control room processes that NESO uses to operate the system. This includes the introduction of the Open Balancing Platform [45] and other process and IT based measures. To date, this has improved the ability of the control room to bulk dispatch a large number of assets near-simultaneously, and fast dispatch assets in a more automated way [46] [47]. However, the focus in the early phases of these programmes appears to have been on improving dispatch of energy-balancing actions, rather than on locational actions.

Box 2: Constraint cost leakage

Constraint costs are often highlighted as one reason that the system needs better locational signals. In recent years, constraint costs have increased from £0.5 billion in 2020 to £1.5 billion in 2022 before falling to £1.2 billion in 2023 [27]. The recent Clean Power 2030 Advice suggested that constraints could be £3.6 billion in 2030 assuming that existing network development plans are delivered, but that these would be higher if new transmission networks were delayed [2].

However, if constraint payments are removed by moving the market to one based on non-firm financial access rights, it will create a significant revenue gap for investors in new generation and storage assets. This could be a particular challenge for those assets, like wind and solar generation, with a high proportion of their levelised cost of energy wrapped up in capital investment. Investors in these assets need high confidence in revenue streams over many years in order to underpin the initial investment. Without these, they expose their investment to significant uncertainty.

The removal of firm access rights is therefore likely to change the behaviour of investors. The desired impact is that it increases the attractiveness of projects located in areas with minimal constraints – this creates a strong locational volume signal on investment. However, if it is not possible to develop sufficient generation capacity in those locations, there will still be a need for capacity in areas where constraints will be prevalent. For these projects to reach a final investment decision (FID), two things are likely to need to happen: firstly, the expected revenue losses from curtailment will need to be recovered from other revenue streams. The obvious cash-flow for renewable generators is to bid for a higher CfD strike price, ensuring that when generating the asset receives sufficient additional revenue to replace that lost to curtailment.

Secondly, because the level of curtailment is uncertain at the point of FID, projects will need to ensure their revenues cover additional risk premiums. Again, this is likely to manifest as further upward pressure on CfD strike prices.

Whilst a move to non-firm access, and removal of curtailment payments, might appear as a short-term cost saving for NESO and, via BSUoS, consumers, it is likely to lead to ‘cost leakage’ with equivalent, or potentially inflated, costs appearing through other cash flows.

It is critical that the full range of cost dynamics is modelled and understood, including the potential for constraint costs to leak to other cash flows.

The introduction of a constraint management market would represent a significant reform, introducing an additional element to the electricity system commercial and regulatory framework. It would require substantial development work to understand the risk of gaming and the interactions between constraint and wholesale markets. A recent report laid out a model for constraint management markets with contracting arrangements stretching from a decade ahead to intraday [28]. This noted both the significant opportunities that constraint management markets, operating ahead of gate closure in parallel with the wholesale energy market, would create, along with several risks that need to be explored further. During 2024, NESO, through the Thermal Constraint Collaboration Project, has also been exploring the potential for constraint management markets as an interim solution ahead of more significant market reform [48].

A simpler reform which could have a direct impact on the ability to cost-effectively redispatch the wholesale market outcome would be to move gate closure from one hour to three or six hours ahead of delivery. This would allow significantly more time for NESO to optimise and deliver the required redispatch, allowing time to run optimisation algorithms that can take account of inter-temporal constraints such as minimum on and off times and energy storage constraints, dispatch the potentially large number of small providers that are likely to form the provider-base in a decarbonised electricity system, and still have sufficient time to ensure that the redispatch is robust and secure.

		Financial access rights	
		Largely firm	**Largely non-firm**
Dispatch arrangements	Self	• Status Quo • NESO faces significant constraint costs including both turn down and turn up elements • Turn down element of constraint costs reimburse market participants for lost revenue and are a factored into investment decisions • Current arrangements support investor confidence thorough firm market access • In addition to locational balancing, the model also experiences significant energy imbalance with market-dispatch failing to align supply and demand nationally.	• Market participants self-dispatch as today. • NESO uses a post-gate-closure system to turn down assets behind a constraint, similar to the BM, but do not pay for turn down of generation • The model requires a mechanism to choose which assets to curtail. Without financial bids and with many having the very similar marginal costs (e.g. near zero marginal cost for wind) curtailment allocation could be arbitrary • Model still requires a BM-style system for turn-up actions in front of an export constraint • Would still face similar energy imbalance issues to the status quo.
	Central	• NESO runs a mandatory day ahead and potentially intra-day centralised auction • Initial dispatch could be (a) physically feasible (in line with network limits) or (b) network-blind • In (a) assets that were in merit but not dispatched due to network constraints need to be identified and reimbursed through constraint payments • In (b) a later BM-style system is still required with little reduction in redispatch volumes • Both mechanisms could reduce system-wide energy imbalances.	• NESO runs a mandatory day ahead and potentially intra-day centralised auction • Initial dispatch could be (a) physically feasible (in line with network limits) or (b) network-blind • Assets not dispatched in the market are not paid, regardless of whether they were out of national-merit or within merit but dispatched off due to system limits • The central dispatch model improves energy imbalance as well as dealing with constraints.

(a)

		Financial access rights			
		Largely firm		**Largely non-firm**	
		NESO	**Market participant**	**NESO**	**Market participant**
Dispatch arrangements	Self	Status quo: the NESO pays significant constraint costs passed to consumers through BSUoS and has large volumes to redispatch after gate-closure.	Status quo: high certainty on revenue stream hence confidence which supports investability. But limited incentive to align operation with system limits.	Removes the requirement for the NESO to pay constraints costs, therefore significantly reduced BSUoS costs to consumers. However, does not reduce the volume of actions required or the time available so the technical challenge remains.	Introduces a **strong locational volume signal** in which the expected constraint and the uncertainty in constraints varies across the country. The reduction in an asset's revenue could be passed to other commercial and regulatory mechanisms e.g. higher CfD strike prices. Greater uncertainty could lead to increased risk premium.
	Central	Opportunity to ensure initial day-ahead dispatch is broadly inline with network limits. Can allow better optimising, cost-efficiency of dispatch and redispatch. However, the NESO still required to pay for assets that were in national merit but not dispatched.	Lose some control: submit a predefined set of asset limits and prices rather than choosing their own dispatch. However, firm access gives continued confidence of revenue. There are particular concerns about dispatch of assets with complex, intertemporal constraints and costs. E.g. batteries	Combination of effects from top left and bottom right boxes: improved operability and early dispatch in line with system limits, and removal of constraint costs from the NESO / consumers.	Combination of effects top left and bottom right: strong locational volume signal, impact on investability through reduced revenue and increased uncertainty leading to a potential increase in e.g. CfD strike prices to replace lost revenue and cover increases risk premiums. A concern about the NESO's ability to dispatch assets.

(b)

Figure 7: Summary of options for dispatch arrangements and access rights. Table (a) describes how arrangements could work and (b) briefly describes the potential impact on NESO and market participants.

There may be concerns with moving gate closure further away from real time. There has been a distinct trend across the world to move gate closure closer to real time, allowing markets to fine-tune their dispatch as delivery approaches to account for firmer forecasts of renewable output and demand and deal with changes in plant availability.

3.2 Reform options for the system services and support mechanism challenge

The options discussed above aim to improve either the dispatch of the wholesale energy market or its redispatch in line with system limits. However, as discussed in Part 2, there are also locational considerations related to the dispatch of non-energy system services and of how support mechanisms allocate payments.

Whilst separate, the questions of incentivising both investment in and operation of assets that can provide system services are closely linked to energy market dispatch. In particular, the potential for non-energy revenues to finance some forms of flexibility assets could be important in ensuring that flexibility gets built in places where it can also support efficient energy market dispatch.

The nature of system-services and other non-energy cash flows also provides the opportunity for greater control. Most of these processes involve NESO or UK Government acting as a 'sole buyer' through either a market-based auction approach or tender rounds. This means NESO can have greater control over the locations in which it purchases services.

The Capacity Market (CM) and government-backed CfDs for renewables represent major national auctions and provide important parts of the investment case for schedulable and variable renewable generators, respectively. Neither CM nor CfDs currently deliver a locational signal, and the second REMA consultation has broadly indicated that the UK Government is not thinking of using them to drive locational signals. However, the focus on Clean Power 2030 and the commissioning of the SSEP means that there is a growing question about how to deliver the locational distribution of generation, demand and flexibility that these strategic plans lay out. Unlike some of the other mechanisms, these auctions could provide a direct opportunity to align the provision of investment timescale revenue streams with the locational aims of a strategic plan. In doing so, they can also capture some inherent elements of value in the provision of either 'capacity' through the Capacity Market, variable renewable capacity through the CfD, or other supported capacity such as hydrogen electrolysers (through the Hydrogen Production Business Model) or in future medium- or long-duration energy storage (through the proposed cap and floor support scheme).

Locational variations in the value of capacity depend on the transmission network connecting it. As mentioned in Table 1 (pg 42), the ability of the transmission network to transport power from capacity purchased in the Capacity Market to demand depends on network capacity aligning with the requirements of the Security and Quality of Supply Standard (SQSS) to be capable of supplying power in a stress event and on the use of appropriate assumptions when setting the SQSS itself. As with other elements of system planning, network capacity has typically followed demand from network connectees. An alternative approach would be to allow generation capacity to support regional and national security of supply by ensuring a fraction of capacity is located in each part of the country, potentially with upper and lower bounds set by the network import and export limits.

Another element of locational value comes from diversity. This is particularly relevant to variable renewables, where resource availability (how windy or sunny it is) tends to be highly correlated in local areas, but less well correlated across the whole country. A 2022 study by Regen suggested that a greater geographical spread of offshore wind would reduce the depth and duration of troughs in the output of the national fleet without significantly reducing total generation [49].

Response and reserve services also require network capacity in order that the flexibility procured can be delivered. For example, AFRY's recent work for NESO, discussed in Part 1, on dispatch and operation, identified the sterilisation of some response because of network constraints as a driver of increased operational costs [18].

Other ancillary services, along with the provision of restoration, tend to be procured via regional tenders. Procurement and planning of some of these services, such as those related to various elements of system stability and voltage support, have been developed through 'pathfinders' over the past few years. Others, such as restoration (previously called black start), continue to use existing processes, but these have developed to reflect changing requirements and provider types. One reform, important for ensuring that GB has the right assets, in the right locations, to provide all the services needed, would be to improve the coordination between the full range of these services, and to align that procurement more closely with capacity procurement through the capacity market. NESO's Market RoadMap programme [50] brings together all relevant market approaches and highlights improvements that will soon be implemented. For example, the stability pathfinder approaches are being embedded in business-as-usual through the development of a coordinated stability market. However, more can be done to look at the issue from the perspective of investors in new low carbon schedulable power stations, energy storage, and other options.

3.3 Interconnectors

Interconnectors are not exposed to TNUoS, BSUoS and transmission loss factors. This means they do not face the existing investment-timescale signals that TNUoS and TLFs deliver. It also means that any attempt to introduce further investment-timescale locational signals or to reform these frameworks to deliver operational timescale locational signals would not affect interconnectors.

The exclusion of GB from the majority of European cross-border balancing arrangements means that interconnectors can neither participate in the Balancing Mechanism nor, in general, use other routes to be redispatched after gate closure.

Box 3 provides an overview of current arrangements and balancing challenges for GB interconnectors.

Box 3: Arrangements for the dispatch and redispatch of interconnectors

The GB interconnector fleet is dispatched through a range of mechanisms. Initially, interconnector owners sell capacity in the forward market up to a year in advance. Then, on day-ahead and intraday timescales, market participants who have purchased capacity can nominate that capacity to flow. The specific arrangements differ across the fleet. Interconnectors to:

- France, Belgium, Netherlands and Denmark are dispatched via explicit day-ahead and intraday auctions.
- Norway are dispatched via implicit day-ahead actions linked to power exchanges operating in GB and Norway.
- The Island of Ireland are dispatched via implicit intraday auctions.

Redispatch options and regulated mechanisms for NESO to adjust the market dispatch are:

- For interconnectors to France, Belgium, Netherlands and Denmark, on intraday timescales, NESO identifies market participants who hold capacity across an interconnector nominated at day-ahead stage and trade directly with these market participants in order to remove those nominated flows.
- For interconnectors to the Island of Ireland, a Cross Border Balancing (CBB) mechanism allows balancing-timescale adjustment of flows.
- NESO can also use Net Transfer Capacity (NTC) restrictions. However, this is only allowed via an Ofgem derogation, as it is treated as a non-market mechanism and is used only as a last resort.

GB is excluded from many of the balancing timescale mechanisms used across the European Internal Energy Market. These include Trans European Replacement Reserve Exchange (TERRE) [51], Manually Activated Reserve Initiative (MARI) [52] and Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO) [53].

Without agreement at system level, it will be challenging to arrange improved balancing timescale adjustment, as an adjustment on interconnector flows in the last hour before delivery in order to respond to a GB issue, need to be paired not just with changes in the flow on the interconnector, but with changes in the generation or consumption of electricity in the connected markets.

For a more in-depth explanation of current arrangements, see the recent Scottish Renewables Report, Getting Interconnectors Right for Net Zero [28].

To overcome these issues, there are several strategies. First, GB could aim to reintegrate into the IEM, allowing it to make use of the Europe wide cross-border balancing mechanisms now being developed and implemented. Second, it could try to remove interconnector exemptions from the cash flows mentioned above. Third, it could pursue approaches to work more closely with stakeholders in connected countries – either market participants or system operators – pre-gate closure. Fourth, it could make better use of regulatory approaches – locational rules or mechanisms – or develop new ones.

The first option, reintegration into the IEM is, at best, a long-term goal. It is not a direction that the UK Government is currently taking, therefore this report does not consider it further.

The second option, removing current exemptions, would involve changing the terms of the Trade and Cooperation agreement, which commits UK Government to ensure there are no network charges on individual transactions across interconnectors [29].

The third option provides more opportunities. Today, the redispatch of interconnectors by NESO is only possible on explicitly traded interconnectors which have both day-ahead and intraday auctions. This limits redispatch opportunities to those interconnectors linking GB with France, Belgium, Netherlands, and Denmark; it excludes those interconnectors to the Island of Ireland and Norway. For these interconnectors, NESO can see the day-ahead dispatch and identify if it has the potential to exacerbate internal GB constraints. If it does, NESO can potentially trade with individual market parties who have nominated flows across the interconnector, and pay for them to adjust their position. The approach is opaque and ad hoc. One alternative would be to invite those market participants to participate in more open and transparent intraday auctions, a process that could be incorporated into the development of constraint management markets. Another alternative is to work together with the connected system operator to develop a market-based approach to redispatch which avoids having to trade with the market participants who hold capacity on the interconnector, and works directly with the wider intraday market of the connected country. This latter option is explored in more detail as one of the reform options.

The fourth option – improving the use of existing regulatory approaches or developing new ones – also provides opportunities. Currently, NESO can use Net Transfer Capacity (NTC) restrictions to limit the capacity of interconnectors available to the market. This can allow it to limit the flow towards zero (although not to set the direction of flow). NTC restrictions are only allowed under a derogation from Ofgem [54] and require that the NESO reimburse the interconnector or parties that trade across it for lost revenue. Currently, because of its status as a regulatory rather than market mechanism, NESO only uses NTC restrictions as a last resort. However, it may be valuable to explore the economics of using these on a more regular basis to manage flows.

Another option in this space is to introduce additional regulatory cash flows for interconnectors that attempt to mimic the signals that a locational price signal would create, whilst avoiding that signal falling on other market participants. This concept was proposed by Frontier Economics [10]. Whilst the approach could theoretically deliver cost-reflective signals, it would face a number of challenges, and would likely struggle to meet the requirements of the TCA.

4 Discussion framework for reform options

This section provides a systematic review of key options based on the discussion of areas for reform above. The review uses a standard format to discuss a wide range of options. The review is based on the following framework:

- **Background:** a brief summary of the background to the potential for reform, including a description of current arrangements, and a rationale for why reform might be considered.
- **What:** a brief description of the reform under consideration.
- **Why:** a summary of why the reform might be considered and what its desired impact would be.
- **How:** a description of how the reform could be implemented.
- **Locational impact:** a description of the locational element, including the type of locational signal that it would introduce (e.g. investment or operational, price or volume, expectation or uncertainty). This will draw out the effect the reform would likely have on different types of asset.
- **Low cost:** the impact that the reform could have on delivering the objective of low overall system costs. Descriptions include impacts that could reduce costs (+), that could increase costs (-), or that might be cost neutral (<>).
- **Security of supply:** the impact that the reform could have on delivering the objective of security of supply. Descriptions include impacts that could increase (+), decrease (-), or be neutral (<>) on security of supply.
- **Net zero:** the impact that the reform could have on delivering the objective of net zero. Descriptions include impacts that could increase (+), decrease (-), or be neutral (<>) on net zero.
- **Other considerations:** this will reflect the discussion of trade-offs in Part 2 and will comment on the practicality of introducing the reform, its potential impact on investability and on market liquidity. It may also comment on other factors relevant to that reform, such as alignment with European rules for interconnector reform.
- **Aligning with a strategic spatial plan:** this will comment on how a reform is likely to interact with a strategic spatial energy plan, for example by delivering incentives which reinforce or work against the requirements of Clean Power 2030 or a future SSEP and whether further consideration needs to be given to mitigating any negative impacts.
- **Conclusion:** A brief conclusion summarising the opportunities and concerns identified and detailing the priority for exploring the option further.

The options and presented allocated to one of five groups as shown in Figure 8. Several of the options could be argued to fit into multiple groups; the categorisation used here is used only to help organise the options and isn't meant to be definitive. Table 4 to

Table 8 summarises the conclusion from each option's systematic review. These conclusions do not, in general, rule options in or out. Rather, they focus on identifying whether there is value in prioritising further investigation.

Group				
Group 1: Interventions to incentivise market participants to align wholesale energy market dispatch with network limits	Locational BSUoS charges on generators and consumers with settlement-period granularity	Reform generation TNUoS	Remove the cap at zero for demand TNUoS charges and change the basis for demand charges	Introduce locational signals from other cash flows to incentivise energy market dispatch
Group 2: Mechanisms for NESO to better organise market dispatch and re-dispatch	Introduce pay-as-clear locational prices for Balancing Mechanism actions	Introduce a pre-gate closure constraint management market	Non-firm access rights	Central dispatch
Group 3: Mechanisms for the locational procurement and dispatch of non-energy services	Locational signals through capacity market: (a) locational minima / maxima (b) locational prices	Introduce (a) locational minima / maxima and (b) locational strike prices in the CfD auctions	Introduce a locational element to frequency response and reserve markets	Better coordination of tendering across technical ancillary services and restoration
Group 4: Changes to market structures and processes	Move gate closure further ahead of real time	Improve NESO IT and control room processes	Introduce Dynamic Locational Transmission Loss Factors with settlement-period granularity	
Group 5: Interconnector specific interventions	Expose interconnectors to a locational shadow price	Develop new SO-SO frameworks for pre-gate closure trading		

Figure 8: Summary of interventions considered in this review

Table 4: Summary of conclusions from the review of interventions based on incentivising market participants to align wholesale energy market dispatch with network limits (Group 1)

Intervention	Conclusion
Locational BSUoS charges on generators and consumers with settlement-period granularity	For the reasons identified by the two recent BSUoS taskforces (primarily: major practical challenges to cost-reflective BSUoS delivering a useful signal) there does not appear to be value in taking this forward.
Reform generation TNUoS	Generation TNUoS is primarily an investment-timescale locational signal and is likely to stay that way. As noted in Ofgem's recent open letter on strategic transmission charging, it currently has high levels of locational differential and uncertainty in future charges. Ofgem has recently argued that these work against delivery of net zero and has suggested a temporary cap and floor to deal with them in the short term in their current form. There is a risk that future TNUoS based on the current methodology (based on the long run marginal cost of investment in the transmission network) will be mis-aligned with a strategic plan for some technologies, particularly renewables and storage, where it creates high charges in areas where a Strategic Spatial Energy Plan (SSEP) requires investment. A full review of the principles on which TNUoS is based should be conducted alongside proposals for how an SSEP would be implemented (e.g. cost reflective vs cost recovery; reflective of the cost of what?)
Remove the floor at zero for demand TNUoS charges and change the basis for demand charges	There could be significant value in removing the floor at zero for demand TNUoS and realigning the basis on which demand is charged locational TNUoS to better reflect the impact that demand has on transmission investment in areas which are generation-dominated. Although Ofgem has expressed a view that neither generator nor demand TNUoS should be used for operational signals, this report suggested there may be value in exploring the possibility of delivering improved locational operational signals through demand-side flexibility.
Introduce locational signals from other cash flows to incentivise energy market	This is unlikely to deliver suitable operational signals: most cash flows are primarily investment- rather than operational-timescale, and except for BSUoS and TNUoS (discussed separately) don't directly reflect market participants' contribution to locational issues such as transmission constraints. Therefore, any alignment is coincidental rather than cost-reflective and could

Intervention	Conclusion
dispatch (e.g. capacity market, CfDs, Transmission Loss factors)	change as the cost drivers and cash flows are inherently uncoordinated. The most promising approach would be to adapt dynamic, locational transmission loss factors which are currently likely to show correlation with transmission constraints. However, they would be difficult for market participants to forecast and are likely to suffer many of the same difficulties as BSUoS reform.

Table 5: Summary of conclusions from the review of interventions based on providing better tools for NESO to organise market dispatch and redispatch (Group 2)

Intervention	Conclusion
Introduce pay-as-clear locational prices for balancing mechanism actions	There is value in investigating this as a way to deliver stronger locational signals to market participants in redispatch, allowing easier forecasting and assessment of likely balancing mechanism revenue streams and allowing assets to build business cases to locate in places favourable to the system and actions taken at or after gate closure to balance it.
Introduce a pre-gate closure constraint management market	Has the potential to provide an important new tool for NESO capable of supporting better outcomes for the technical and financial aspects of redispatch. If market participants can forecast future NESO actions through constraint management markets, or the extent to which the market might offer long-term contracts, the reform also has the potential to inform locational investment in flexible assets located in places favourable to the system.
Non-firm access rights	Reductions in the cost of operating the system might be expected through removal of the entitlement to compensation for denial of access which is associated with firm access rights. However, such changes would also change network users' expected revenues and introduce uncertainty, with a potential impact on those users' other costs. Those costs would need to be recovered and risks hedged via some other means if they are to continue to use the network. There is most likely to be value in exploring non-firm access rights for two-way energy storage assets as an approach to maximise the connection of flexibility without unduly limiting network access for other assets.
Central dispatch	Has the potential to deliver a system dispatch which better aligns both with system and network limits from the day-ahead stage onwards, helping to reduce the volume of redispatch significantly

Intervention	Conclusion
	and utilise the fleet of assets more optimally. The utilisation of individual assets may differ from the way existing owners optimise their positions under current decentralised arrangements, as the central dispatch aims to optimise against system-wide objectives rather than optimising each asset individually. However, there is some risk that the central dispatch algorithm isn't fully capable of optimising the operation of individual assets and the wider system; the impact on network users' revenues will depend primarily on access rights.

Table 6: Summary of conclusions from the review of interventions based on providing mechanisms for the locational procurement and dispatch of non-energy services (Group 3)

Intervention	Conclusion
Locational signals through capacity market: a) locational minima/maxima b) locational prices	Despite the second REMA consultation's position not to introduce locational capacity market signals "as a standalone option", we think there is value in exploring them further, considering the locational need for assets capable of delivering on future definitions of 'stress events' (including multiple types of event over longer and shorter timescales). The capacity market at present procures simply capacity. An ability to deal with stress events in a system with a significant capacity of variable renewables should also entail procurement of sufficient energy. However, an ability to access the energy depends on there being sufficient network capacity. A reformed, locationally aware capacity market could ensure energy resources are placed where there already is, or is expected to be, enough network capacity or it can be aligned with further network expansion and wider strategic infrastructure planning through the SSEP.
Introduce a) locational minima/maxima and b) locational strike prices in the CfD auctions	Despite the second REMA consultation's position not to take forward the introduction of locational CfD auction signals as a "primary option", this report concludes that there is value in exploring further, either to support delivery of a locational SSEP or to reflect the value of a geographically diverse fleet. As in the case of capacity market reforms, locationally aware CfD auctions could be aligned with the needs of an SSEP, ensuring new capacity is built where network capacity is, or is expected to be, available or it can be aligned with future network expansion. This would need to

Intervention	Conclusion
	be delivered through coordination with future plans for seabed leasing.
Introduce a locational element to frequency response and reserve markets	There appears to be significant potential for some response and reserve capacity to be procured in areas where it cannot deliver the system-services required, e.g. where response 'headroom' is 'sterilised' behind a transmission constraint. Therefore, there would appear to be value in considering how to introduce locational considerations into the procurement and scheduling arrangements for response and reserve provision in the future.
Better coordination of tendering across technical ancillary services and restoration	Individual system services tend to have strong locational signals through zonal tendering rounds. However, improving the coordination and visibility of tenders over the coming years would allow assets to more easily combine contracts to build a business case where there is locational correlation between service needs.

Table 7: Summary of conclusions from the review of interventions based on changing market structures and processes (Group 4)

Intervention	Conclusion
Move gate closure further ahead of real time	Providing more time to NESO for balancing mechanism-based redispatch following gate closure will relieve the technical challenge and may allow a lower-cost lower-carbon redispatch to be organised. The argument against this – that removing time for the intraday market to optimise the initial market dispatch would increase costs – appears unproven.
Improve NESO IT and control room processes	Improvements have been made, particularly regarding improved non-locational energy balance, through the introduction of the Open Balancing Platform. NESO should prioritise improvements to locational balancing, e.g. Bids and Offers to solve network constraints.
Introduce Dynamic Locational Transmission Loss Factors with settlement-period granularity	There are significant implementation challenges for dynamic TLFs and it is uncertain how effective the intervention would be. This would depend on the ease with which market participants would be able to forecast TLFs. The approach is likely to suffer similar challenges to those identified for dynamic, locational BSUoS.

Table 8: Summary of conclusions from the review of interventions based on providing interconnector-specific interventions (Group 5)

Intervention	Conclusion
Expose interconnectors to a locational shadow price	Theoretically, this intervention can deliver a locational price signal to interconnectors whilst leaving other assets facing the national wholesale price. However, it is likely to face significant practical challenges, create significant barriers to market-participants trading across interconnectors, including regulatory risk arising from uncertainty over how such a system might be 'tweaked' in the future. It is likely to struggle to align with the Trade and Cooperation Agreement and European Internal Energy Market rules, as such, there may be limited value in developing the idea further.

Develop new SO-SO frameworks for pre-gate closure trading	There appears to be significant potential for the NESO to work proactively and cooperatively with connected System Operators to deliver a more transparent and predictable trading framework utilising (NE)SO to SO pathways (rather than the current NESO to market-participant pathway). There is an apparently successful example operating within European IEM rules between Germany and Denmark.

4.1 Reform generation TNUoS

4.1.1 Background

- Transmission Network Use of System (TNUoS) charges aim to deliver two objectives: firstly to recover the allowed costs of building and operating the transmission network. Secondly, to provide a cost-reflective investment signal on market participants related to the cost of transmission that they drive. The principle is that the charging signal is derived from the long-run marginal cost of transmission.
- The methodology results in a strong locational cost signal on generators and storage, with higher costs for these assets in areas with an excess of generation over demand. There is also significant uncertainty over TNUoS charges for future years and this introduces an additional risk-based locational signal that is strongest in areas with highest forecast future TNUoS.
- The TNUoS methodology, which was initially conceptually relatively simple and based on an assumption that market participants tended to use the system in broadly similar ways, has grown increasingly complicated over the past decade. For example, adjustments to account for the correlation and intermittency of wind and solar has led to multiple sets of tariffs.
- Importantly, the scale of locational variation is growing, driven by the increasing reliance on north-south flows and the use of more expensive transmission technologies, particularly offshore HVDC links between Scotland and England.
- Under the first and second REMA consultations, TNUoS reform has been presented as an important existing investment signal, encouraging generation to locate closer to demand. In the second consultation, TNUoS reform is presented as one part of the alternative package. The consultation notes that “locational investment signals sent by TNUoS are currently considered broadly cost-reflective, however improving the stability of the charge may require a trade-off between cost-reflectivity and predictability. It is possible that some reform options could reduce the strength of the locational TNUoS signal, but equally possible that others enhance that signal.”[4]
- More recently, Ofgem has indicated concern at the potential scale of future TNUoS charges and their locational differences and the tension between these charges and delivery of Clean Power 2030. In a September 2024 open letter, Ofgem indicated that it is “important that we consider how best to ensure the transmission charging regime does not unduly hinder low carbon investment to meet the expedited target”[39]. Ofgem identifies a number of challenges that the current methodology creates: the volatility of charges; negative impact on investment decisions for assets that could be crucial for clean power 2030; and that the methodology also increasingly delivers large credits to southern generators. The letter states that Ofgem’s current view is that “a temporary cap and floor on wider TNUoS charges for generation would offer the most efficient type of intervention” [39].

- A number of proposals have been put forward to mitigate both the large cost-based and risk-based locational signals:
    - **Change the basis on which charges are cost-reflective:** One proposal put forward, by Optic, aims to set TNUoS charges not on long-term marginal transmission investment costs, but on overall impact on system costs including both market dispatch and transmission investment [55]. This would involve modelling the development of the electricity system based on a particular scenario and optimisation of both the dispatch of assets and investment in transmission infrastructure. TNUoS charges would be set based on the differences they would create in a) locational shadow prices and b) transmission investment. Initial analysis suggests this approach would lead to lower locational differences. In an illustrative example presented as part of the code modification process, locational differences reduced from around £40/kW under the existing methodology to £25/kW (Annex 5 [55]).
    - **Fix TNUoS charges for an extended period:** one of the concerns for investors is the uncertainty over future TNUoS charges as well as their magnitude. For example, developers bidding for a CfD contract need to take account not just of their central estimates of the project's lifetime TNUoS charges, but also of the risk that they could be substantially higher than expected. This could lead developers to add a risk premium to their strike price bid and so push up overall costs. One way to manage this, separate from any intervention to reduce TNUoS locational costs differences, is to allow projects to fix TNUoS costs for a certain amount of time at the point of CfD bid or Final Investment Decision. Ofgem have recently turned down a code modification to implement a ten-year fix, concluding that it would be expensive for consumers without sufficient benefit [56]. However, the decision acknowledges the challenge that the volatility of TNUoS locational charges creates and indicated a desire across working group members and Ofgem, as the regulator, to find a solution to the issue.
    - **Temporary cap and floor:** Ofgem's rationale for this approach, put forward in its September 2024 open letter, related to the importance of aligning the TNUoS methodology with delivery of CP30 and the longer-term Strategic Spatial Energy Plan. Ofgem notes that it may be some time before the TNUoS implications of the approach are fully understood but that it is important that the pace and timing of generation investment is not compromised [39].

What?	**Reform generation TNUoS**
Why?	TNUoS aims to deliver a long-term cost-reflective signal to market participants, aimed at ensuring they internalise the cost of the transmission network investment they drive. The current approach will deliver extremely high locational signals to generators, to the point where new net zero investment in areas where there is

	already an excess of renewables over demand, could be put at significant risk. This underlies Ofgem's recent recommendation to introduce a temporary cap and floor on TNUoS for generators.
How?	There are a range of reform options which include a) adjust the parameters within the current methodology (e.g. expansion factors or security limits); b) change the cost-reflective basis for TNUoS (e.g. as proposed by Optic); c) move strategically planned assets from cost-reflective charging to cost recovery only; and d) remove locational charging and implement a form of 'postage stamp' charges.
Locational Impact?	Any of the above reforms would lead to a reduced locational price signal faced by generators on investment timescales. This would reduce the cost reflectivity of the charging approach. In reducing the size of the locational differential, it would also reduce the locational uncertainty faced across a project's lifetime.
Low Cost	**-** Reducing locational TNUoS signals would reduce the incentive on generators to locate in places more valuable to the system. This could lead to an increase in whole system costs. **+** High TNUoS is likely to feed into CfD clearing prices. Given relatively similar project costs faced by developers of one type of asset (e.g. onshore wind or offshore wind), future TNUoS charges are likely to represent a major differentiator between projects in terms of costs. If projects bid into CfD auctions competitively, based on their underlying costs base; and if auctions require buying projects in higher TNUoS zones in order to deliver the capacity needed, locational TNUoS charges will have direct upward pressure on clearing prices. If the locational TNUoS differential were reduced, these projects would be able to bid lower into CfD auctions, reducing the clearing price that is paid to all projects in that year and technology pot.
Security of Supply	**<>** Intervention would have limited impact on security of supply
Net zero	**+** Locational TNUoS signals tend to impact most strongly on renewable generators. High TNUoS Zones are driven by, and impact on, the development of wind in northern GB. In addition, renewable investors recover their investment over very long timescales, circa 15 years or longer, meaning that future uncertainty can have a significant impact on investability and cost of capital. Reducing locational differences could significantly reduce the investment pressure on the renewable generation we need to deliver net zero. **+** Energy storage is another asset type that could have a significant impact on our ability to integrate the variable and uncertain output of wind and solar. The current system charges these assets generation TNUoS. Very high locational TNUoS liabilities are likely to have a strong disincentive on batteries (and other forms of energy storage) from locating in the north of GB, regardless of their operational pattern or practical impact on transmission investment.

	Whilst there are other ways of dealing with energy storage – for example, changing the methodology for calculating TNUoS for these assets – reducing locational differentials can encourage energy storage to locate in areas close to renewables.
Other considerations	**Risk of arbitrary charging arrangements:** the current desire to reduce the scale of locational TNUoS creates a new tension with the concept of cost reflectivity. At least in theory, once the principle of cost reflectivity is chosen – in this case cost reflectivity against long-run transmission investment costs – based on the rationale of internalising transmission costs into project investment decisions, the remaining work of designing a tariff is to identify how best to achieve the cost-reflective goal. Ofgem's 2024 open letter still argues that it is important to retain the cost reflectivity principle. However, the situation is now that our current best attempt at providing a cost-reflective answer is no longer the one that we want. Therefore, what level should a cap be set at? The need to move away from our current cost-reflective answer introduces a degree of arbitrariness. **Impact on demand:** Whilst this intervention focuses on generation TNUoS (see next intervention for a demand-side proposal), it is worth noting that under current arrangements there is a floor at zero for locational demand TNUoS. This floor is active across much of GB, from the English Midlands northwards. This means that in practice, there is no locational demand signal from TNUoS in the northern half of GB under the current arrangements.
Strategic plan alignment	Softer locational TNUoS is likely to align better with the generation aspect of a strategic plan based on renewables. Whilst strong locational signals for demand may better align with the same strategic plan, those signals do not exist under current arrangements because of the floor.
Conclusion	Generation TNUoS is primarily an investment-timescale locational signal and is likely to stay that way. It currently has high levels of both locational differential and uncertainty in future charges. Ofgem has recently argued that these work against delivery of net zero and has suggested a temporary cap and floor to deal with them in the short term. There is a risk that future TNUoS based on the current methodology (based on the long-run marginal cost of investment in the transmission network) will be mis-aligned with a strategic plan for some technologies, particularly renewables and storage, where it creates high charges in areas where a Strategic Spatial Energy Plan (SSEP) requires investment. A full review of the principles on which TNUoS is based should be conducted alongside proposals for how an SSEP would be implemented (e.g. cost reflective vs cost recovery; reflective of the cost of what?)

4.2 Remove the cap at zero for demand TNUoS charges and change the basis for demand charges

4.2.1 Background

- Current demand TNUoS consists of two major components: a locational element that is charged based on Triad demand and a residual element which is charged based on banding of annual energy consumption and connection voltage [57]. The locational element is calculated in a similar way to the cost-reflective locational element of generation TNUoS, however it is then floored at zero to ensure that demand is never incentivised to consume energy during Triad[14] – hence increasing national peak demand – to receive a TNUoS payment.
- The advent of a large capacity of geographically clustered and temporally correlated renewables means that it is often not periods of peak demand that drive the need for additional transmission, but periods of high renewable output. Demand located in areas with a high renewable penetration will tend to reduce the need for transmission during these periods of high renewable output if the demand consumes energy when wind or solar output is high.
- More formally, and using Scotland and wind as an example, the need for new transmission between Scotland and England is driven by economic efficiency rather than security of supply-based considerations. This means transmission costs are balanced against curtailment costs to get the ‘right’ capacity of transmission – more transmission capacity will lead to lower constraint costs. In effect, the need for transmission is related to the net generation behind a transmission boundary. In this context net generation is defined as generation minus demand.
- The impact of demand in this situation will depend on whether it consumes when regional renewable generation is high. If it does, it will reduce the need for transmission. This impact will happen regardless of whether demand consumes at the time of system peak demand, as measured by Triad.
- Therefore, rather than charge the locational element of demand TNUoS against Triad, it would be more appropriate to charge it against some measure of peak zonal net generation with the charge negatively related to that contribution. For example, a demand that always operates when the wind was blowing (regardless of whether it operates when the wind wasn’t blowing) would receive a large negative locational demand TNUoS charge, whilst a demand that never operated when the wind was blowing would receive a zero or positive TNUoS charge (regardless of whether it operated when the wind wasn’t blowing).
- One outcome of such an approach would be an operational-timescale signal on demand with an incentive to consume during periods of high zonal net generation (for example in Scotland, an incentive to consume when it is windy)

[14] Triad periods are the three settlement periods with the highest demand between November and February with each separated by at least 10 days. Prior to 2023 demand charges were entirely based on Triad demand, now the largest element of demand charges – the residual – is calculated based on annual energy demand and the effect of Triads is much smaller.

and either to avoid consumption, or a charge that was ambivalent to whether consumption occurred, during periods of low zonal net generation (for example in Scotland, when it was calm).

- Negative demand TNUoS delivered in this way would also avoid the issue of encouraging consumption at times of national peak demand.
- Ofgem has indicated that it does not believe that TNUoS should be used for delivery of operational signals. However, it does not appear that they have explored this type of TNUoS arrangement for demand.

What?	**Remove the cap at zero for demand TNUoS charges and change the basis for demand charges**
Why?	It could lead to a charge which was more aligned with demand's impact on transmission investment costs and would therefore better deliver the cost-reflective principle inherent in current TNUoS arrangements. It could also introduce an operational locational signal which, in areas of high penetration of variable renewables, could encourage demand to align its operation with renewable generation in the same zone.
How?	Change the charging base for demand TNUoS from Triad demand to one based on correlation with net regional demand. Combine this with removal of the floor on demand TNUoS.
Locational impact?	Demand located in regions where generation exceeds demand would be incentivised to try to align their consumption with zonal generation in order to minimise their TNUOS charges. It would create both investment and operational signals: On investment timescales, it would introduce a stronger price signal that would be particularly strong for those assets capable of ensuring they consumed during periods of high renewable output. However, developers may find it more difficult to assess future TNUoS charges or payments, which would also introduce a locational signal in the form of increased uncertainty. On operational timescales, it would introduce a price signal encouraging operation during periods of high zonal generation. For example, in Scotland where wind capacity significantly exceeds peak demand, it would reward consumption when wind output was high.
Low cost	**+** The reform would introduce a price signal to incentivise investment and operation of demand in ways that reduced the need for transmission investment. It would also likely, over time, as new investments are made, support lower levels of transmission constraint.

Security of supply	**<>** The impact would have a limited impact on security of supply.
Net zero	**+** The reform would tend to align investment in, and operation of, demand with renewable output.
Other considerations	Ofgem has expressed a view that TNUoS should not be used for operational signals. It justifies that position by noting that effective operational TNUoS signals would require a step change in the complexity of charging arrangements and the ability of market participants to respond. Ofgem's issues should be explored for this reform option – can it be delivered without significant complexity? Or with a level of complexity that is appropriate for the type of consumers that may respond to it?
Strategic plan alignment	The approach would likely align with a strategic plan as it would incentivise an alignment of demand and renewable generation, both geographically and temporally.
Conclusion	There could be significant value in removing the floor at zero for demand TNUoS and realigning the basis on which demand is charged locational TNUoS to better reflect the impact that demand has on transmission investment in areas which are generation dominated. Although Ofgem has expressed a view that neither generator nor demand TNUoS should be used for operational signals, this report suggested there may be value in exploring the possibility of delivering improved locational operational signals through demand-side flexibility.

4.3 Introduce locational signals from other cash flows to incentivise energy market dispatch

4.3.1 Background

- Without the use of locational wholesale energy pricing or the application of dynamic locational BSUoS, there is no direct, cost-reflective route to incentivise market participants to align their energy dispatch with locational limits.
- However, those market participants are exposed to a range of other cash flows which, whilst fundamentally driven by other system needs, could be used to incentivise particular patterns of electricity market dispatch.
- This approach is unlikely to be preferable in theory as incentives would not be cost reflective and would be, at best, correlated with locational system constraints rather than causal.
- However, the correlation between some cash flows and transmission constraints could potentially be strong enough to drive behaviour that supported better overall outcomes.
- The choice of cash flows and mechanisms which could be used include regulated charges, capacity market or CfD cash flows, or the application of transmission loss factors.
- TNUoS is one example of a regulated cash flow, although reforming this to deliver operational signals is something that Ofgem has indicated it does not believe is appropriate [43].
- Other regulated cash flows include the levies charged to demand to cover the costs of the capacity market and support mechanisms. At present, these are all flat charges with no locational or operational-timescale variation.
- There is the potential to use the CfD mechanism to deliver operational signals. For example, the second REMA consultation briefly explores the idea of removing CfD uplift payments during periods of constraint as one of its deemed CfD Variations [4]. This approach could be applied to existing CfD designs as well as deemed CfDs. It would create a strong price signal during periods of constraint. The signal would not change operational behaviour for intermittent renewable generators who can only generate when it is windy or sunny and, as such, although delivered on operational timescales, it would in effect, for these assets, be a locational investment signal.
- The most likely option to provide a correlation with transmission constraints is a signal related to transmission losses. Transmission losses depend on the amount of power flowing over a transmission circuit and on its resistance. Therefore, losses are highest when there are large flows of energy from one part of the country to another. These also tend to be periods when constraints are likely.
- However, the correlation is not perfect: transmission losses can be high in situations where the transmission network has a large capacity that is being heavily utilised– for example during a settlement period when flows are 80% or 90% of the network’s transfer capacity. In these situations, there is no constraint,

but losses are high. It may still be appropriate to allocate losses to market participants on a cost-reflective basis in order to ensure they internalise their contribution to those losses. But it would not be appropriate to use the losses as a proxy for transmission constraints and hence to apply a stronger signal than required by the losses themselves.

- It is important to note that this option is about using a variety of cash flows in a non-cost-reflective way to correlate specifically with transmission constraints. There is a separate question whether to include locational signals in each of the cash flows in direct relation to the costs they cover.

What?	**Introduce locational signals from other cash flows to incentivise energy market dispatch (e.g. capacity market, CfDs, Transmission Loss factors)**
Why?	It would introduce a proxy for cost-reflective charges on market participants, contributing to the need for curtailment costs using any mechanism which has the potential to correlate with transmission constraints.
How?	**TNUoS:** continue to apply strong locational TNUoS incentive signals, potentially strengthening the locational element of demand TNUoS. Use this approach to disincentivise generation or demand to locate in areas where it contributes to transmission constraints (which may correlate with areas where they would drive increased need for transmission). This would likely remain an investment-timescale signal, however, there may be options to introduce an operational signal, for example, if demand charges were related to an asset's contribution to regional net demand. (see TNUoS reform option below). **Capacity market, CfD and other support mechanisms:** 1) tailor the allocation of contracts for capacity, CfD support or other support mechanisms to assets that are less likely to contribute to constraint costs. This would introduce an investment-timescale signal that would affect operation over time through the geographical spread of the assets available for operation. 2) Adapt the rules for payment to discourage contribution to constraints. For example, reform CfD structures to remove payments during periods when the generator is contributing to a constraint. This would introduce a locational 'rule'-based signal within the CfD mechanism. **Transmission loss factors:** Develop a dynamic, locational transmission loss factor methodology that applies a locational factor, based on contribution to losses, to the metered output or consumption.
Locational impact?	Not reviewed
Low cost	Not reviewed

Security of supply	Not reviewed
Net zero	Not reviewed
Other considerations	Some of the other considerations for introducing locational signals in each of the revenue streams discussed can be found under the reform options which look specifically at that option.
Strategic plan alignment	Not reviewed
Conclusion	This is unlikely to deliver suitable operational signals: most cash flows are primarily investment rather than operational timescale, and except for BSUoS and TNUoS (discussed separately) don't directly reflect market participants' contribution to locational issues such as transmission constraints. Therefore, any alignment is coincidental rather than cost-reflective and could change as the cost drivers and cash flows are inherently uncoordinated. The most promising approach would be to adapt dynamic, locational transmission loss factors which are currently likely to show correlation with transmission constraints. However, they would be difficult for market participants to forecast and are likely to suffer many of the same difficulties as BSUoS reform.

4.4 Introduce pay-as-clear locational prices for balancing mechanism actions

4.4.1 Background

- The Balancing Mechanism (BM) is the primary route for managing transmission constraints in today's system as well as managing non-locational issues including ensuring a national energy balance. As such it is the primary tool for NESO to redispatch the market outcome in a way that is physically feasible and secure.
- This means the BM is a key route to the delivery of locational signals to assets located in a particular place relative to transmission constraints.
- BM actions are pay-as-bid rather than pay-as-clear.
- There are also interactions with other regulatory tools, such as the Transmission Constraint Licence Condition (TCLC), which places a rule on holders of a generation licence that they should not make excess profit from bids to turn down generation behind an export constraint.
- These characteristics tend to reduce the incentive on market participants to invest in some assets based on their location.
- There are different situations in front of and behind an export constraint.

4.4.2 Behind an export constraint

- Market participants behind an export constraint can bid to trade energy in the Balancing Mechanism by reducing generation or increasing demand relative to their dispatch in the energy market. If the Bid is accepted by the ESO the price awarded is the bid price.
- For those with a generation licence (generators and storage) the Transmission Constraint Licence Condition (TCLC) requires that the Bids to turn down output should not allow a generator to seek to obtain an excess benefit in relation to reductions in electricity generation in transmission constraint periods [58]. This effectively requires that the bid is no more than the short-run marginal revenue impact of being curtailed, with allowances for a number of more minor effects, such as the impact of a bid acceptance on wear and tear or operational efficiency.
- The result is that licenced generators, including storage operators when they are reducing a scheduled discharge, cannot make a significant short-term profit by having Bids accepted to reduce output in order to ensure transmission constraints are not breached. Many renewable generators bid at negative prices, reflecting the loss of support mechanism payments that will result from reducing their output. This means that NESO must pay to reduce their output. However, one of the key rationales for the TCLC is that these generators cannot bid significantly beyond the value of lost support revenue.

- For those without a generation licence (the demand-side and non-licenced generators) who are not subject to the TCLC, the incentivise is to estimate the most expensive bid that the ESO will have to accept to resolve the constraint and bid slightly below that level.
- There also several other reforms coming through that will affect the situation. Balancing and Settlement Code modification P462 aims to remove support mechanism payments from the costs that a generator can recover from BM bids and reimburse them as side-payments. That means under the influence of the TCLC, renewable generators with ROCs or CfDs will bid close to zero – their true physical short-run marginal cost [59]. This means that other assets such as flexible demand will face a significant lowering of the price at which competitors are bidding.
- A similar result could come from introducing a fully deemed CfD mechanism where CfD uplift were paid regardless of physical generation. This would lead to another situation where renewable generators would no longer have to include their lost support payments in their bid price for the BM. Overall this (and the P462 proposal) will reduce constraint costs, although at the price of an increase in other cash flows – CfD uplift payments for deemed CfD, and 'side' payments for P462.
- In 2023 Ofgem issued a call for input on possible changes to the TCLC including applying it to a wider range of assets [60].
- The key point of this tangle of regulatory rules is that because accepted actions are only paid at the bid price, and because the level of Bids allowed is constrained by interaction between different sets of regulations, any locational signal is opaque at best. And for many assets (those with a generation licence) the prohibition of making short-term profit on bid actions removes an important pathway to building a long-term business case for investment.

4.4.3 In front of an export constraint

- Market participants in front of a constraint can offer to sell energy, meaning an increase in generation or a decrease in demand relative to their dispatch in the wholesale market. These actions are also paid based on the price submitted.
- Unlike actions behind an export constraint, the TCLC does not apply and assets can choose to offer at prices significantly higher than their short-run marginal costs.
- In its other role, helping manage energy constraints, balancing mechanism Offers higher than marginal cost are an accepted feature, with so-called 'scarcity pricing' representing an important part of the business case for peaking generators.
- Today, the pay-as-bid feature continues to dilute the locational signal to market participants.

4.4.4 Overall effect

- The result is that the balancing mechanism delivers a locational volume incentive, reflecting the differing scale of opportunity for Bids or Offers to be expected across the country. But the pay-as-bid structure weakens the locational price signal, particularly for assets behind a network constraint.
- There is the potential to move from pay-as-bid to pay-as-clear on a locational basis.
- The effect of this would be to introduce a stronger locational price signal and to allow assets to make short-term profits related to location in order to build long-term business cases.

What?	**Introduce pay-as-clear locational prices for balancing mechanism actions**
Why?	It would provide a clear, more transparent locational price signal with greater forecastability for redispatch actions and clearer opportunity for assets to recover investment costs through the BM.
How?	Rather than pay BM Bids and Offers based on pay-as-bid, set up a zonal clearing price system with zones based on key constraints. All actions accepted in a particular zone receive the zonal price.
Locational impact?	Creates a clear locational BM price signal for all assets involved in delivering redispatch through the BM. It would provide a well-defined opportunity for market participants to develop a locational business case and recover capital costs. Combined with other reforms such as improved balancing mechanism IT infrastructure and control room processes, it could support stronger locational business cases for flexible assets. It also has the potential to remove regulatory risk for investors who are currently unclear as to how the TCLC might be interpreted in future.
Low cost	**+** Over time assets will be incentivised to locate where needed and to provide redispatch services at lower costs **-** The reform has the potential for a significant transfer from consumers through inframarginal rent, particularly important in the short term before the system supported a change in the geographical distribution of assets. It will be important to explore this issue in detail as part of any further investigation.
Security of supply	**+** Over time assets will be better located around system needs and therefore should support a more secure system.
Net zero	**+** provides an improved locational business case for low carbon assets such as energy storage **+** can drive reduced curtailment over time as flexible assets locate appropriately and provide alternative options for redispatch instead of curtailing renewables **<>** The reform doesn't directly favour low carbon over high carbon assets, but can be combined with other reforms to do so.

Other considerations	**Practicality:** the design of zoning for the balancing mechanism needs careful consideration, ensuring that key constraints are captured. The system model and optimisation approach would require a step change in balancing mechanism processes. However, the scale of change would be smaller than that required for reform such as central dispatch. **Market liquidity:** There would be a likelihood of illiquid zones and accompanying risk of market power. It would be important to develop approaches to identify and manage low liquidity. For example, agreeing on administrative pricing arrangements when a lack of liquidity is identified.
Strategic plan alignment	The reform provides a clearer route-to-market for flexible assets, which is likely to align with any strategic plan, incentivising flexibility to locate in areas where the combination of generation, demand and transmission capacity are most likely to require redispatch.
Conclusion	There is value in investigating this as a way to deliver stronger locational signals to market participants in redispatch, allowing easier forecasting and assessment of likely balancing mechanism revenue streams and allowing assets to build business cases to locate in places favourable to the system.

4.5 Introduce pre-gate closure constraint management market

4.5.1 Background

- Currently the GB system relies primarily on post-gate closure redispatch via the balancing mechanism. In addition, the ESO has the scope to trade with the market ahead of gate closure where this is expected to be cheaper than relying on the balancing mechanism. Volumes of pre-gate closure traded energy have been growing in recent years: in the financial year 2022-23, 14% of constraint costs, and 19% of volume, were delivered through pre-gate closure trading [61].
- The mechanism for forward trading involves the ESO approaching market participants bilaterally and agreeing trades with them to adjust the planned operation of specified assets. (This differs from a market participants' normal market trading where they can meet any commitment from across their portfolio)
- Whilst the ESO publish some information on trading volumes and costs, the process of trading is opaque and ad hoc.
- Another option is to formalise the process of pre-gate closure trading into a formal ‘constraint management market’ where open and transparent auctions are used to procure response ahead of gate closure.
- The ESO has trialled a Local Constraint Market across the B6 and B4 boundary since early 2023 [62]. This is for assets which can respond to day-ahead and intraday manual instructions to change their planned operation. It is limited to non-balancing mechanism assets and to generation turn-down/demand turn-up actions behind the export constraint (it does not operate an equivalent market in front of the export constraint). Because of the design, and several different interactions with aggregation, supplier and metering issues, volumes have been small.
- Some stakeholders are concerned that such an approach would increase the potential for gaming because it involves parallel operation of both a non-locational wholesale market for initial dispatch and a locational redispatch market. If this is poorly designed, this could provide market participants with near risk-free arbitrage between the two prices, leading to a significant transfer from consumers for little gain. This trading strategy is sometimes referred to as ‘inc-dec trading’ (standing for increment-decrement) [27] [63] [64] [65].
- However, there are potential market designs which would limit or control opportunities for gaming. For example, the use of long-term contracts signed for specified annual volumes of response with prices fixed and then a short-term constraint management market to dispatch that annual volume at appropriate times.
- There are also similar incentives for gaming with the interaction between the wholesale market and the balancing mechanism, albeit those two do not overlap in time. These have been appropriately managed through the introduction of specific regulatory rules – licence conditions for example.

- The approach has been explored qualitatively in a previous report by one of the current authors [27], has been proposed by other reviews [11] [26], and was mentioned as an option within the second REMA consultation.

What?	**Introduce pre-gate closure constraint management market**
Why?	Provide new tools to NESO with longer lead times for redispatch. Formalise existing ad-hoc pre-gate-closure trading. Lock in options for redispatch volumes and prices in advance to manage NESO and consumer risk.
How?	Introduce a pre-gate-closure constraint management market for redispatch with NESO acting as a single buyer. This would effectively formalise existing trading activity. A mature constraint management market might involve day-ahead auctions, intraday dispatch or a link to the balancing mechanism with balancing mechanism utilisation prices fixed through day-ahead auctions, and long-term availability or 'option' contracts to provide some degree of revenue certainty to providers and price hedging for NESO.
Locational impact?	Creates locational constraint markets with an **operational price** and **operational volume** signal. The addition of long-term contracts could also help manage **price and volume risk** and deliver an **investment timescale locational signal**. Overall, the approach could improve both the locational business case and locational operational incentives for flexible assets, including battery storage, long-duration energy storage and flexible demand. One example of relevant demand assets are hydrogen electrolysers which currently do not have a strong incentive to locate in areas where their operation would reduce curtailment [34].
Low cost	**+** Provides NESO with new tools which can be used for cheaper than expected balancing mechanism actions. **+** Provides additional revenue streams to support locational business cases for investors, encourage new providers to specific locations, ultimately it could reduce operating costs for the NESO. **<>** The use of long-term contracts could involve the NESO taking on more risk by procuring constraint management services when constraint forecasts are less certain. However, that also provides new tools for NESO to better manage consumer risks through the use of hedging instruments.
Security of supply	**+** Over time assets will be better located around system needs and therefore should support a more secure system.
Net zero	**+** Provides improved locational business case for low carbon assets such as energy storage **+** Can drive reduced curtailment over time as flexible assets locate appropriately and provide alternative options for redispatch instead of curtailing renewables **<>** The reform doesn't directly favour low carbon over high carbon, but can be combined with other reforms to do so.

Other considerations	**Practicality:** this would be a major new component to the overall electricity system commercial and regulatory framework. As such, it would constitute a significant reform. Whilst of similar complexity to a move to locational wholesale energy pricing, there is more opportunity to introduce it in stages. **Investability:** a voluntary constraint management market would avoid adversely impacting on assets that are not suited to provision of constraint management flexibility. At the same time, it would increase the investability in assets that can respond if they are located appropriately relative to constraints. **Gaming:** there is a risk of gaming, and this could be more extensive than the risk that currently exists with the balancing mechanism. Understanding this requires dedicated work.
Strategic plan alignment	Provides a clearer route-to-market that is likely to align with the requirements of a strategic plan.
Conclusion	Has the potential to provide an important new tool for NESO capable of supporting better outcomes for the technical and financial aspects of redispatch. If market participants can forecast future NESO actions, or the extent to which the market might offer long-term contracts, the reform also has the potential to inform locational investment in flexible assets located in places favourable to the system.

4.6 Non-firm access rights[15]

4.6.1 Background

- One foundation of the current market framework is firm financial access rights. This means that market participants who purchase access to the transmission system, initially through a connection charge and then an ongoing use of system charge, can trade with other market participants in a similar position across the whole of GB without considering the physical feasibility of their trades.
- When NETA was originally introduced in 2001, there was an expectation that access rights would move to a tradable framework and that the allocation of and trade in these rights would replace the balancing mechanism as the primary method of managing constraints [66].
- Whilst a tradable market in access did not appear, the enduring solution that NETA and then British Electricity Trading and Transmission Arrangements (BETTA) settled into where participants kept firm access rights, including the right of compensation if physical access rights were curtailed (primarily via the balancing mechanism). New access rights were awarded in return for long-term commitments by market participants, initially through securities associated with the connection process, and then by an annual transmission use of system charge.
- Firm financial access rights were instrumental in the growth of renewables during the 2010s. In conjunction with a change in connection policy from Invest and Connect, where assets are connected only when wider transmission upgrades are completed, to Connect and Manage, where assets connect ahead of some transmission upgrades, firm rights maintained the investor confidence needed to grow the renewable fleet.
- However, firm financial access rights are part of the framework which drive constraint costs, as the NESO has to reimburse generators for their lost revenue when the system is physically incapable of transporting its power.
- One reform option, considered as part of the second REMA consultation, is to remove firm access rights for some or all market participants and replace them with non-firm rights.
- Non-firm access rights could be designed with a range of characteristics, for example, the ‘firmness’ could vary with time (e.g. firm rights during peak hours only) or with system-state (e.g. firm rights unless there is a transmission outage). Firm rights could also be made available to a local zone with non-firm rights to the wider system. Or all rights of access could be made non-firm.
- Non-firm access rights are implicit in most locational pricing markets. With nodal locational pricing, assets have no firm access rights beyond their node, whilst with zonal locational pricing assets may have firm access rights within the zone but non-firm rights beyond it.

[15] The 2024 REMA Autumn Update [92] laid out a minded to position that: “we are no longer considering reforms to transmission network access rights for new generators under reformed national pricing. This is due to concerns that introducing non-firm access rights for these assets could lead to operational inefficiencies and would only provide an incomplete locational signal.”

- However, non-firm rights could be used without the need to move to locational wholesale pricing. An example of this approach has been developed as part of the solution to the connection queue. Battery assets will soon be offered non-firm rights for a time-limited period in return for early connection to the network [67].
- The second REMA consultation considered several options for how a move to non-firm rights would be facilitated. This includes either administrative or auctioned allocation of access rights to new connecting assets, through to full non-firm access rights for all market participants, including existing assets. However, it noted that the more radical reforms would likely need to be combined with either zonal pricing or a move to central dispatch.
- The consequence of a move to non-firm access is that when the system is physically incapable of accepting generation (or potentially, incapable of serving demand – see below) NESO can direct that asset to reduce its generation/consumption and has no obligation to pay the asset to do so. This would remove balancing mechanism revenue streams for generators turned down because of transmission constraints and it would increase uncertainty for those assets associated with forecasts of the likely prevalence of constraints.
- However, it would introduce a potentially strong locational investment signal. This would be a locational volume signal as it would reduce the volume of energy (or other system services such as response and reserve) that a market participant can expect to trade in the future. This would include both a quantity-based and a risk-based signal, as not only would the expected volume of tradable energy reduce, but the level of uncertainty over constraints would increase in a location-specific way.
- Non-firm access rights for demand would raise additional questions. The same theory as that for generation applies – where the system is physically incapable of serving demand, it would not have the right to consume energy. Such an approach may have value for certain types of flexible demand, for example, the demand from batteries when charging, or for some forms of highly flexible demand where consumers have specifically signed up to those arrangements. However, limiting consumers' access to the system at a more general level is unlikely to align the overall objectives of security and reliability of supply.
- The use of non-firm arrangements might be most effective for two-way energy storage where assets require access rights for both generation and consumption, but that the incentives to use either their import or export access rights will be clearly aligned with particular system conditions. For example, there is likely to be a strong correlation between batteries wishing to use their import (consumption) access rights during periods of high national renewable availability, as this would imply low prices and excess energy generation above the level of inflexible demand. The corollary is that there would be a strong negative correlation between renewable availability and batteries wishing to exercise their export (production) access rights. Under current arrangements, the system operator and network owners have to take account of the *potential* for batteries to wish to export at times of high renewable output, as that is what their firm access rights allow. Non-firm access rights have the potential to remove that need and allow a more effective system design without, potentially, a significant

impact on battery business cases. This approach is already been implemented through connection reform processes [67].

What?	**Non-firm access rights**
Why?	Remove the requirement to pay generators for curtailment because of network constraints, sometimes presented in the media as 'paying generators to do nothing'.
How?	Remove financially firm system-wide rights of access to the system for generating market participants for either a) new entrants or b) all assets. This would mean that generators would only be guaranteed the right to trade energy to demand within a limited geographical (network) area. This could be as small as 'nodal' meaning non-firm access beyond the connected node, or 'zonal' meaning non-firm access with firm rights to trade power within the zone and non-firm rights for trades between generators and demand in different zones. Demand would likely retain firm access rights in line with the societal objective to provide low cost, reliable and low carbon energy to consumers. However, access rights for some subsets of demand, e.g. demand associated with flexibility, could also be changed.
Locational impact?	Introduces a locational volume signal for generation. Although energy sales would continue to be at a single national price, the volume of power that could be sold by generators would be subject to the availability of non-firm access rights. Generators themselves would receive an investment-timescale incentive, which would be based on the expected level of access availability with an attached uncertainty, both of which would vary by location. It would also introduce a rule that could be incorporated into an operational-timescale mechanism which would allow NESO to curtail generation without compensation. Assuming demand retains its firm access rights, there might be a limited impact on the demand side. For any flexible demand with non-firm access rights, similar logic would apply to that described above for generation.
Low cost	**+** Removes the need for the ESO to pay curtailment costs to turn down generators (although the cost of replacing that generation on the far side of the constraint, the turn-up cost, remains). **-** Decreases revenue for renewables and other supported assets, likely to mean a need for higher support mechanism payments (e.g. CfD strike prices). **-** Greater uncertainty could increase the cost of capital that developers need to cover, creating a further upward pressure on cost.
Security of supply	**+** Reduces the cost of curtailing market participants in order to maintain security of supply (although does not reduce the cost of replacing that generation on the far side of the constraint). **-** Reduced revenue and increased risk could create a barrier to investment, that could cumulatively impact on security of supply.

Net zero	**-** The reform is likely to have a particularly significant impact on variable renewables as availability of renewable resources tend to correlate with transmission constraints and, even in a well-developed system with near optimal levels of transmission capacity, constraint of zero-marginal cost generation could still be significant in a future decarbonised system. **-** Reduced revenue and increased risk could create a barrier to investment in low carbon technologies, slowing down the transition.
Other considerations	**Legality:** if rights for existing assets were changed (option b) above), this could be open to legal challenge. **Practicality:** decision rules would be required for curtailment of similar assets, e.g. multiple wind farms, very similar costs/parameters behind the same constraint. Detailed attention also needs to be given to distributed assets to ensure a level playing field. **Investability:** reduces investability for new assets because of significant locational volume risk. **Grandfathering:** may be required for existing assets (effectively moves option b) back to a)). **TNUoS:** current transmission charging arrangements are predicated on the assumption of firm access rights. Therefore, a significant change in access rights would likely require further reforms of TNUoS arrangements. **Dispatch mechanism:** there is significant interaction between non-firm access rights and central or self-dispatch. The two reforms would benefit from being considered together.
Alignment with strategic planning	There are no technical barriers to either aligning with the strategic plan, however non-firm connections are likely to lead to more difficult investment / higher cost of capital, (unlikely fully mitigated e.g. through an appropriately designed deemed CfD) for renewables in areas likely to be favoured by a strategic plan.
Conclusion	Reductions in the cost of operating the system might be expected through removal of the entitlement to compensation for denial of access associated with firm access rights. However, such changes would also change network users' expected revenues and introduce uncertainty, with a potential impact on those users' other costs. Those costs would need to be recovered and risks hedged via some other means if they are to continue to use the network. There is most likely to be value in exploring non-firm access rights for two-way energy storage assets as an approach to maximise the connection of flexibility without unduly limiting network access for other assets.

4.7 Central dispatch[16]

4.7.1 Background

- The GB wholesale energy market currently operates on a self-dispatch model. That means individual market participants choose how and when to run their assets and inform the NESO of their decisions. The NESO only intervenes to balance supply and demand and to resolve physical constraints, such as network limits. The self-dispatch model goes hand-in-hand with the current bilateral market design, allowing market participants to trade bilaterally as they wish and dispatch as they wish.
- Self-dispatch of generation is particularly important for market participants with a portfolio of assets. Here, the market participant buys and sells energy as an entity and then chooses which of its assets to use to meet its commitments. A portfolio allows a market participant to manage uncertainty, particularly given the growth in variable renewables such as wind and solar: they can sell a certain quantity of generation ahead of time, adjusting those forward sales based on longer term forecasts of renewable generation, however if wind outturn is lower than expected they can adjust to increase output from schedulable generators or batteries. This approach allows excellent opportunities for portfolio-level optimisation and risk management, but can add to the level of adjustments made by the market participant. NESO, who are blind to the internal portfolio optimisation, see only a series of adjustments to asset-level physical notifications.
- With self-dispatch, some markets operate on a central dispatch model. Central dispatch is usually required for nodal locational pricing and for many instances of zonal locational pricing. However, as was the case in GB prior to 2001, it can also be used alongside a nationally priced market. The island of Ireland, for example, currently operates a centrally dispatched nationally priced wholesale market.
- Central dispatch operates via a single, central, mandatory auction which is cleared by an independent market operator. Market participants submit Bids and Offers on an asset-level (rather than a portfolio level) basis and the market operator clears the auction, minimising costs subject to a range of physical limits, such as network constraints. The market operator then issues dispatch instructions which define the operating point of each individual asset. A common arrangement is to run day-ahead and intraday auctions, with the intraday auctions adjusting the day-ahead dispatch to reflect improving forecasts of demand and supply availability.
- A key difference between self and central dispatch is the level of control that asset owners have over the running of their assets and portfolios. With central dispatch, market participants have less scope to optimise their portfolio

[16] The 2024 REMA Autumn Update [92] laid out a minded to position that: "We are not minded to take forward centralised dispatch under either reformed national pricing or zonal pricing at this stage, but are open to considering the evidence that the NESO are gathering on it.".

internally, rather each asset faces the central dispatch algorithm individually. This leaves the potential for the algorithm to overlook some considerations that owners of assets with complex inter-temporal operating characteristics can currently take into account. For example, battery operators are likely to be scheduling their assets across several revenue streams (e.g. wholesale trading, balancing and response and reserve provision).

- One area of compromise is to allow 'self-commitment' within the wider central dispatch design. This approach has been discussed by several projects, including NESO's ongoing market reform programme [16]. It could allow those assets that wanted to sign long-term bilateral forward contracts, or otherwise to lock in an operating schedule ahead of the central dispatch auction. This would avoid the need to wait for the market to clear. As NESO note, the proportion to the market that is centrally scheduled varies in existing central-dispatch, self-commitment, markets [16]. However, neither NESO, nor others who have discussed this area, describe clearly what is meant by self-commitment. Whilst self-commitment is practical in a market with limited transmission congestion, as constraints rise there is the risk that self-committed generators lead to overloading of the network which could remove any benefits of moving to a centrally dispatched market at all.

What?	**Central dispatch**
Why?	Provide NESO with significantly more control over dispatch and the ability to align dispatch directly with system limits from day-ahead stage onwards.
How?	Require mandatory participation in day-ahead and / or intraday auctions for dispatch, with the auction paying a centralised pay-as-clear price. The dispatch algorithm could include a representation of the network, either at the nodal or zonal level, and the initial dispatch could, therefore, be consistent with network and other system limits. There would be different options for the mechanism by which assets were dispatched 'on' because of locational effects (where they were nationally out of merit), and how their prices feed into the calculation of the clearing price. The details would depend on the interaction with the decision over access rights. The market design may include an explicit ability for some assets to 'self-commit' and bypass the auction. However, this is likely to either a) need to be limited to commitments that, on their own, don't breach any system or network limits or b) include a rule for rejecting a subset of self-commitment actions in order to retain system limits. Neither of these options satisfactorily deals with the existing issue of an excess of generation behind a single constraint, as a large fraction of that generation can simply choose to self-commit.
Locational impact?	Does not change locational incentives for market participants in its own right (this is because if firm access rights were maintained, the equivalent of constraint payments would still be required – see discussion in sections 4.6 and 3.1). Rather, it provides a locational

	mechanism which gives NESO control over the initial market dispatch. The potential to align initial market dispatch with system limits is likely to significantly reduce the volume of redispatch required and could allow some other locational incentives to be more effective.
Low cost	**+** Allows day-ahead dispatch that aligns with transmission constraints. This can provide a mechanism which can lead to a more cost-optimal solution to the physical problem of the best dispatch. For example, in comparison with the current system, by delivering a more certain dispatch at the day-ahead stage when more options remain available, and significantly reducing the volume of post-gate closure redispatch actions. **-** Some flexibility providers hold the view that centralised dispatch algorithms will be less efficient at dispatching complex assets than self-dispatch, particularly those involved in the provision of flexibility and those with intertemporal constraints.
Security of supply	**+** Improves day-ahead dispatch, allowing potential security of supply issues to be identified much earlier in the run up to delivery.
Net zero	**+** Can dispatch flexibility optimally across the fleet rather than relying on individual asset-level decisions.
Other considerations	**Practicality:** requires significant new IT infrastructure and a major change for both NESO and market participants. This would require testing, development, assurance and integration with a central dispatch system and could be expensive / technically challenging for at least some market participants. **Optimality:** there is a potential trade-off between asset-level optimal dispatch and system-level optimal dispatch. The dispatching algorithm would be limited to optimise based only on the parameters captured and could miss subtleties related to individual assets, however this could be a reasonable trade-off if it delivers an outcome which better delivers the overarching societal objectives. The intertemporal dispatch problem, involving network constraints, multiple time periods, and uncertainty around forecasting system states even minutes or hours ahead, remains extremely challenging to solve in practice.
Alignment with strategic planning	There are no technical barriers to aligning central dispatch with the strategic plan as long as central dispatch provides access to the appropriate operational revenue streams.
Conclusion	Has the potential to deliver a system dispatch which better aligns both with system and network limits from the day-ahead stage onwards, helping to reduce the volume of redispatch significantly and utilise the fleet of assets more optimally. The utilisation of individual assets may differ from the way existing owners optimise their positions under current decentralised arrangements, as the central dispatch aims to optimise against system wide objectives rather than optimising each asset individually. However, there is some risk that the central dispatch algorithm isn't fully capable of optimising the operation of individual assets and the wider system; the impact on network users' revenues will depend primarily on access rights.

4.8 Locational signals through capacity market: a) locational minima/maxima b) locational prices

4.8.1 Background

- The Capacity Market was established under the 2013 Energy Act in order to ensure “sufficient reliable capacity in the GB electricity market at minimum cost to consumers.” [68] This is often referred to as ‘capacity adequacy’.
- Underlying the current capacity market design is an assumption that the energy from capacity providers can be moved around the country from generator to demand across transmission and distribution networks without significant limitations. It is assumed, therefore, that during a stress event there will not be significant network constraints.
- This assumption is underpinned by network design standards such as the Security and Quality of Supply Standard (SQSS) [69] which sets the capacity of the transmission network that must be built to facilitate the flow of power. The SQSS sets out the assumptions to use when modelling the network for planning and operational reasons. It includes a ‘security background’ which is to be used to determine the level of secure transfer capability required from the transmission network across key boundaries based on a realistic, if generic, scenario, including the distribution of generation and peak demand.
- Whilst the capacity market may deliver the economically efficient capacity of system-wide generation, to ensure that the output of that capacity can reach demand, the transmission network should comply with the SQSS and the assumptions within the SQSS must be appropriate.
- This approach reflects the wider understanding that network development follows from the prevailing view on future market development. It implies that the most appropriate way to develop the whole system is for the market to decide where commercial assets should be located, and the network should be developed to facilitate that.
- That is not the only approach that could be used. A process that co-develops both generation and network may be better suited to a net zero system.
- Strategic planning suggests a movement toward the third option with the strategic planning process itself co-optimising supply capacity (through the capacity market), network capacity, variable renewable capacity, storage, interconnection etc. by making use of mechanisms such as the capacity market, CfD, planning processes, grid connection policies etc. to deliver it.
- The second REMA consultation identified a number of issues with the current capacity market design including the high carbon intensity of existing capacity market providers, and the need to secure the system against a much wider range of possible stress events.
- DESNZ had previously considered whether a locational element should be introduced to the capacity market. This could, for example, provide a separate price for capacity in different parts of the country or it could introduce ‘locational

minima' which ensures a minimum capacity be procured via the capacity market in each of a set of pre-defined areas of the country.

- The second consultation "discounts introducing a locational element to the capacity market as a standalone option". However, it is not clear whether that implies that it will remain under consideration alongside other options.
- Any future locational element in the capacity market would need to relate to its function. The second consultation suggests that there is the potential for the function to develop from the delivery of capacity adequacy on a GB-national basis to a function which aims to deliver not just the national quantity but, at a more granular level, the different 'characteristics' of capacity that are needed. This could include the right type of assets, with the right technical capabilities, in the right locations. If this were the case, there would then be a clear rationale for a locational element in procurement.
- There are different ways the 'the right location' could be defined:
- If there is a risk of insufficient network capacity to transport generation in one location to demand in another, the framework should discourage the procurement of capacity in that location. This could involve changing the relationship between the SQSS and the capacity market from one where the network follows market to one where the two are co-optimised.
- If there are underlying dependencies which depend on location and affect the ability of multiple providers to deliver capacity, there is a value in diversifying location along with other characteristics. (For example, if multiple gas power stations depend on the same piece of gas network infrastructure, there is an underlying risk that a fault in that gas infrastructure sterilises the contribution of multiple power stations to electricity system security).

What?	**Locational signals through capacity market: a) locational minima/maxima b) locational prices**
Why?	Provides a clear locational a) volume and b) price signal into the procurement of the capacity market, which rewards/discourages capacity located in areas where it is most / least needed and can encourage a greater geographical diversity. It can support the delivery of a specified distribution of assets as identified in a strategic spatial plan.
How?	Reform the capacity market auction design to include either a) specified locational maxima and minima by zone, or b) split into a 'pot' system with different locational pots which clear at different prices. Each pot can include maxima and minima, or other inter-relationships between the volume procured in each pot and the total volume.
Locational impact?	The intervention will affect capacity market revenue for all future capacity market providers. Option a) will introduce a locational volume investment timescale signal which could increase the probability of receiving a contract in some areas and reduce it in others.

	Option b) would, in addition, create a locational investment timescale price signal which would reward capacity providers in areas of relative capacity scarcity. Both options could create a stronger incentive to invest in specific areas of the system.
Low cost	**-** The reform would likely to lead to increased capacity market costs because of additional locational constraints on capacity market auction requiring more expensive capacity to be purchased. **+** But any increases in total capacity market costs would need to be compared against additional value delivered by the auction via a better locational distribution of providers delivering cost reductions elsewhere in the commercial and regulatory framework. **-** Option a) would increase the overall cost paid by consumers for the capacity market if capacity that was out-of-merit nationally, but was accepted because of locational minima, was allowed to set the national clearing price, i.e. in this scenario, clearing prices, paid to all capacity providers, would increase. This could be managed through additional rules about how out-of-national-merit Bids affect the clearing price, or through option b) which would mean that assets in different parts of the country received different prices.
Security of supply	**+** Introducing a locational element to the capacity market has the potential to increase security of supply by ensuring a diverse locational distribution of capacity and providing a framework to manage regional capacity adequacy issues.
Net zero	**<>** capacity market reform to deliver lower carbon capacity is likely to come through other routes. For example, the second REMA consultation suggested options to prefer low carbon providers over high carbon providers.
Other considerations	**Capacity market purpose:** the current objective is "sufficient reliable capacity in the GB electricity market at minimum cost to consumers." Its purpose is set by the type of 'stress event' that it is required to solve, which itself comes from the makeup of the system. Today, expectations are that stress events would be of relatively short duration. The future system will likely need to be secured against several types of stress event. One option could be to introduce, explicitly, the concept of a locational stress events into the set of events against which the capacity market responds to. This might be implemented in conjunction with reform of the SQSS, which sets the requirements for transmission capacity required for secure (and economic) system operation. It is important that *locational* reforms are considered in the context of wider capacity market context. **Market liquidity:** A risk associated with splitting the capacity market by location is that capacity market zones become illiquid with the associated risk of market power developing. It will be important to consider this risk if developing this option further.
Alignment with strategic planning	A locational capacity market could act as a tool for delivering elements of a strategic spatial energy plan. For example, the strategic plan could include an indication of the quantity of firm capacity required in each region of the system, or a lower and upper

	bound for the quantity in each zone. These values could then be integrated as a set of minima within the capacity market.
Conclusion	Despite the second REMA consultation's position not to introduce locational capacity market signals "as a standalone option", we think there is value in exploring them further, considering the locational need for assets capable of delivering on future definitions of 'stress events' (including multiple types of event over longer and shorter timescales). The capacity market at present procures simply capacity. An ability to deal with stress events in a system with a significant capacity of variable renewables should also entail procurement of sufficient energy. However, an ability to access the energy depends on there being sufficient network capacity. A reformed, locationally-aware capacity market could ensure energy resources are placed where there already is, or is expected to be, enough network capacity or it can be aligned with further network expansion through the SSEP.

4.9 Introduce a) locational minima/maxima and b) locational strike prices in the CfD auctions

4.9.1 Background

- Contracts for difference (CfDs) provide an additional revenue stream, on top of wholesale market revenue, linked to a reference price which is set equal to the day-ahead price realised on power exchanges. CfDs are awarded by competitive auction with the strike price set 'pay-as-clear' based on the most expensive strike-price bid which receives an award. There are a number of 'pots' in each CfD auction, with technologies allocated to those pots based on different criteria. Currently, criteria tend to be related to technological maturity.
- As renewable technologies such as onshore wind, solar, and fixed-bottom offshore wind have reached maturity, the CfD can be argued to have moved from a subsidy – paying generators more than the market price for their output – to a risk management or revenue stabilisation tool – where generators accept a fixed price for 15 years, potentially below the expected (i.e. the central forecast) wholesale price over that period – in return for high confidence (lower risk) around that revenue stream.
- Currently, there are no direct locational elements in the CfD. Auctions do not consider location as a criteria for award, nor are there different strike prices by location. Once allocated, strike prices, wholesale market trading opportunities, and reference prices are all 'national'.
- The only indirect locational signal comes via the treatment of Transmission Losses via seasonal, zonal, Transmission Loss Factors which adjust the metered quantity of energy exported from the CfD generator to account for their impact on transmission losses. This creates an indirect investment-timescale locational signal.
- There is also an important interaction between CfDs and the balancing mechanism and financial access rights. CfD payments are only made based on metered volumes, therefore where generators are constrained off through the balancing mechanism they lose any CfD payments. The current framework allows for those costs to be recovered by including the lost revenue in a wind farm or solar farm's balancing mechanism bid price. If firm financial access rights were removed, then the revenue stabilisation that CfDs currently provide would be lost to the extent that a generator expected to be curtailed.
- The REMA process has considered options for introducing locational elements into the CfD process. These include:
    a. Locational minima/maxima: setting a minimum or a maximum capacity to be procured in a particular region.
    b. Locational pricing: running separate auctions, or a more complex single auction, which returns location-specific strike prices. For example, setting up locational 'pots'.
- The second REMA consultation concluded that "we are not therefore continuing to develop the option of introducing a locational element to the CfD allocation

process as a primary option for sending locational investment signals. However, we will pay due consideration to the design of the CfD and its allocation process with respect to reforms in other areas." [4]
- One rationale for ruling this out is the difficulty of using the approach to send an effective locational investment signal. This is partly because CfD allocation comes relatively late in the development process for projects, with potentially years of site selection, environmental surveys and planning and consenting processes completing before a project bids for a CfD. The consultation also expressed concerns about whether increased CfD costs would deliver clear additional system benefits.
- Whilst the REMA consultation has ruled this out, the authors believe that it should still be considered as an option.

4.9.2 Other support mechanisms

- The discussion above relates specifically to CfDs. A similar argument could be made regarding other support mechanisms including the revenue cap and floor provided to interconnectors, the future cap and floor being developed for long-duration energy storage, the Regulated Asset Base (RAB) approach to supporting new nuclear, the Dispatchable Power Agreement (DPA) currently being used to support carbon capture and storage stations and potentially suitable for hydrogen power stations in future, and the Hydrogen Production Business Model (HPBM) available to electrolysers.
- An important difference in context is that CfDs are competitively allocated, whilst none of the other mechanisms involve competitive mechanisms to allocate contracts or set prices. Only the HPBM has a stated ambition to move to competitive auctions in the near future. The remainder involve bilateral negotiations that offer support on a bespoke, project-specific basis.
- It may be possible to design administratively allocated support mechanisms that include a locational signal. For example, requiring government to include a penalty or a reward based on location once the other project parameters had been fixed. However, given that the overall level of support reflects the investability and the balance of costs and revenues for the project, it would be difficult to ensure this was an objective signal.
- Therefore, this report does not consider locational elements in support mechanisms other than the CfD at this stage, but notes that it may be possible, particularly for any mechanism that involves competitive allocation, in the future.

What?	**Introduce a) locational minima/maxima and b) locational strike prices in the CfD auctions**
Why?	Provides a clear locational a) volume and b) price signal into the procurement of renewable generation, which rewards/discourages capacity located in areas where it is most/least needed and can encourage a greater geographical diversity in the CfD fleet.

	It can support the delivery of a specified distribution of assets as identified in a strategic spatial plan.
How?	Redesign the CfD auction to consider location, for example introduce locational minima/maxima in each individual technology pot, or through development of a more complex auction methodology which considers aggregate locational capacity across multiple technology pots. Alternatively, a specific 'locational uplift or downlift' could be applied to strike prices achieved under the existing auction design.
Locational impact?	The locational impact will only apply to assets with a CfD contract. It will provide an investment timescale locational signal either a) via a volume incentive or b) both a volume and price incentive for any assets aiming to gain a future CfD, currently expected to be primarily variable renewables. There would be significant interaction between this (or any) CfD design and a decision to remove firm access rights from CfD generators.
Low cost	**-** Option a): increase in overall costs as projects bidding a lower strike price in the auction may be skipped in order to meet locational minima using more expensive projects. Overall bill impact depends on how these projects which would have been out-of-merit nationally affect the clearing price. **+** Option b): could mitigate the unnecessary economic transfer between generators and consumers by limiting higher strike prices to only those generators within the specific locational pot. Particularly important given the scale of locational TNUoS and its potential uplift of strike prices under existing model. **<>** This could include the security of supply value inherent in geographical diversity as well as, for wind or solar, the smoothing of some of the intermittency from a geographically diverse fleet.
Security of supply	**<>** Impact is likely to be small, but there could be some improvement in security of supply from greater geographical diversity of generation assets.
Net zero	**<>** The intervention will have limited impact on decarbonisation as it would largely only adjust the location at which variable renewables are supported. If overall costs change significantly, there could, however, be an interaction with CfD budgets. **+** However, if the approach led to a distribution of wind and solar that better aligned with network availability, it could reduce curtailment relative to a counterfactual where that was not implemented.
Other considerations	**Practicality:** The intervention could be implemented within the current framework, which already uses pots for technologies. Adaptation of the auction structure and allocation framework would be relatively straightforward in principle, although there may need to be some thought about how to deal with cross-cutting 'pots' (e.g. the interaction between locational pots and technology pots). **Investability:** The intervention would not change the fundamental operation of the CfD scheme and should not have a significant effect on the investability of successful projects. The implementation

	of option b) may reduce some projects' strike prices, however, assuming they bid at a sustainable level, their strike price should remain sufficient for the project to remain investable**.** **Market liquidity:** there is a significant risk that CfD auctions lose liquidity if potential projects are split among too many pots.
Alignment with strategic spatial planning	A locational CfD could act as a tool for delivering elements of a strategic spatial energy plan. For example, the strategic plan could include an indication of the quantity of variable renewable technologies in each region of the system. These could inform maxima/minima in the CfD auctions.
Conclusion	Despite the second REMA consultation's position not to take forward the introduction of locational CfD auction signals as a "primary option", this report concludes that there is value in exploring further either to support delivery of a locational SSEP or to reflect the value of a geographically diverse fleet. As in the case of capacity market reforms, locationally-aware CfD auctions could be aligned with the needs of an SSEP, ensuring new capacity is built where network capacity is, or is expected to be, available or it can be aligned with future network expansion.

4.10 Introduce a locational element to frequency response and reserve markets

4.10.1 Background

- Currently the ESO are increasing the volume of response and reserve procured through day-ahead auctions. This is happening through the development of the dynamic response suite (DC, DM, DR) [70] and balancing product including Balancing Reserve [71] and Quick Reserve [72] introduced in 2024.
- These mechanisms involve a day-ahead auction conducted through the Open Balancing Platform (OBP) in which the ESO specifies the capacity required on a national basis for each settlement period or EFA block the following day. Contracts are awarded based on prices subject to meeting technical requirements. Location does not play a part in winning a contract.
- This means that some capacity can be sterilised by transmission constraints. For example, the ability to increase generation or reduce demand in a specified timescale is a key requirement for both ‘dynamic response – low’ services and Positive Balancing Reserve. However, if an asset providing either service is behind an export constraint, and if the reason for a low frequency event (e.g. the loss of a power station), is on the far side of that export constraint, those assets cannot be used without breaching the network limit.
- AFRY’s work for NESO as part of its scheduling and dispatch case for change specifically talks about this issue in relation to balancing reserve [73].
- One option is to introduce a locational element to the procurement of response and reserve services.

What?	**Introduce a locational element to frequency response and reserve markets**
Why?	Ability to deliver frequency response and reserve can be locationally dependent – for example, capacity can be sterilised if it is separated by a constraint from the source of the energy imbalance driving the need for the response or reserve utilisation.
How?	Adjust the market clearing algorithm used for the dynamic response suite and for the new balancing reserve product to a) place minima or maxima on volumes procured for each service in different zones or b) introduce a locational price through the clearing process which rewards service provision in zones where need outstrips supply and vice versa.
Locational impact?	Provide either a) a locational volume signal or b) a locational price and volume signal for providers of response and reserve. This signal would be delivered on operational timescales (day-ahead auctions) and, if suitably predictable and stable, could translate into investment signals, depending on the economics of particular projects.

	Note that this would also create locational timescale investment signals for an asset that provides response and reserve services but could be able to support the system in other ways.
Low cost	**+** Avoids procuring capacity that is sterilised by a constraint. **+** Avoids inframarginal rent where more expensive providers in specific locations set the clearing price. **+** Can encourage capacity in locations where it is valuable, increasing the supply base. **-** Option a) could increase the clearing price, paid to all providers, if more expensive assets are needed because of locational constraints and these could set the clearing price. Option b) could manage this by offering different clearing prices in different places.
Security of supply	**+** Ensures available response and reserve capacity will be procured in areas where it can be physically used.
Net zero	**<>** No direct impact on net zero, but it would help align resources and availability purchasing in locations that support a net zero system.
Other considerations	**Practicality:** NESO would need to use a forecast of constraints at the day-ahead stage to constrain the response and reserve auctions. At this point, there is significant uncertainty over the level and timing of constraints 12-36 hours in advance. It will be important to reflect the uncertainty and the central forecast in any procurement mechanism. **Investability:** signals could drive investment in new assets in areas where they are most required. For example, this could be important for short-duration batteries which can reach investment decisions with lower long-term certainty on revenue than some other net zero electricity assets. **Market liquidity:** need to consider what happens where there are ‘zones’ with low liquidity of supply.
Alignment with strategic spatial planning	Likely to align with a well-designed strategic spatial plan that has considered the need for assets to support effective and low-cost system operation.
Conclusion	There appears to be significant potential for some response and reserve capacity to be procured in areas which cannot deliver the system-services required, e.g. where response ‘headroom’ is ‘sterilised’ behind a transmission constraint. Therefore, there would appear to be value in considering how to introduce locational considerations into the procurement and scheduling arrangements for response and reserve provision in the future.

4.11 Better coordination of tendering across technical ancillary services and restoration

4.11.1 Background

- There are several technical services that the NESO procures, a number of which are location dependent. These include:
  - **Stability**: the NESO describes stability as “the inherent ability of the system to quickly return to acceptable operation following a disturbance. The term is used to describe a broad range of topics, including inertia, short circuit level and dynamic voltage support.” (pg 88 [50])
  - **Voltage support/reactive power services**[17]: the need for reactive power provision is location dependent, therefore assets in areas where reactive power injection/consumption is often required can see a locational investment and dispatch signal. Some reactive power provision is required from generators as a condition of the grid code and where this is dispatched by NESO, the asset is paid the Obligatory Reactive Power Service Price [74]. Therefore, for this service there is the potential for a locational volume-based signal (as being dispatched is location dependent). Additional reactive power capability is procured by regular tenders and could deliver both a locational volume-based signal (as gaining a contract tends to depend on being in the right location) and a locational price signal (as different contract prices could be awarded to reflect the differing locational value). However, dispatch of capability is often through the balancing mechanism and involves NESO having to adjust real power dispatch (sometimes called MW dispatch) as well as reactive power dispatch (sometimes called MVar dispatch).
  - Following on from voltage pathfinder projects which explored the potential for locational tendering, NESO now runs a Network Service Procurement approach [75] which aims to procure long-term contracts to cover reactive power requirements without relying on balancing mechanism dispatch.
  - **Restoration:** this is the process of restarting the grid following a National Power Outage (NPO), colloquially known as a Blackout. NESO is required to have in place processes to restart generation and reenergise the grid. Restoration is procured locationally via competitive tenders [76] and requires providers to maintain the capability to start without an external supply (many power stations require a strong, existing AC grid to support starting up. This is not possible following an NPO). In addition to the contract for services, some restoration power stations may need to be ‘warm’ in order to deliver their services, this

[17] The terms reactive power provision and voltage support are often used interchangeably: changing the low injection or consumption of reactive power is the usual way to manage voltages.

can lead to NESO dispatching them through the balancing mechanism in order that there is always a restoration service provider available in each zone of the country that is operationally capable of restarting within a few hours.

- For assets capable of providing multiple technical services, there are a number of locational signals available to influence investment decisions, through a variety of dispatch mechanisms, each controlled by the NESO.
- Many assets could provide multiple technical services, and the strength of the locational signals from each type of locational signal would be increased if they were procured in a coordinated way. For example, if contracts for voltage support, stability and restoration in a particular zone were all procured at the same time, weaker locational signals from each could be combined to give a sufficiently strong signal to sway investment decisions.

What?	**Better coordination of tendering across technical ancillary services and restoration**
Why?	Many assets can provide multiple technical ancillary services and restoration, and the strength of the locational signal from each service would be increased if they were procured in a coordinated way. For example, if contracts for voltage support, stability and restoration in a particular zone were all procured at the same time, weaker locational signals from each could be combined to give a stronger investment signal.
How?	Introduce a coordinated procurement and dispatch approach covering at least stability, voltage and restoration. Offer contracts for all three service types through a joint auction with equal contract lengths designed to support investment in assets that can provide these services, critical to security of supply, in specific locations. This could include a 10-year schedule of tender rounds across all services, consistency of zoning across services, or single auctions for multiple services with options for participants to include prices which vary depending on the number of different services they are contracted for.
Locational impact?	The change will impact on revenues for assets providing various stability, voltage support (reactive power provision) and restoration services. The changes would lead to a coordination of revenue streams for these assets rather than a direct impact on the scale of those streams. However, asset owners may change their tendering behaviour to reflect the fact that they can recover their fixed costs over a larger number of contracts. Some of these assets will also provide other services including capacity, response and reserve, and wholesale energy market trading. Therefore, changing the locational incentives on investment for technical services could have an impact on the assets available for other activities within the electricity system commercial and regulatory framework.

Low cost	**+** A more coordinated approach could reduce the cost of providing services as providers could have increased confidence of being able to recover costs across multiple-revenue streams.
Security of supply	**+** The approach is likely to improve the provision of security of supply by giving better signals for investment by assets capable of providing critical security of supply services. The improvement in signals would come from greater transparency and certainty in the tendering approach.
Net zero	**+** Technical ancillary services represent an aspect of power system operation which remains relatively carbon intensive. Coordinated tenders, particularly if combined with approaches which reward low carbon providers or limit fossil fuel providers, could accelerate the decarbonisation of ancillary services.
Other considerations	**Practicality:** developing a more coordinated approach to service procurement requires NESO to have a clear understanding of the need and to coordinate that vision through a detailed roadmap across all technical services. Some progress has been made since the introduction of the System Operability Framework (SOF) strand of work in 2014 by NESO and predecessors [77]. The most recent articulation of this coordination is the Market Roadmap publication [78]. However, despite this work, there is significantly more potential to improve alignment. **Investability and Market liquidity:** both improve as ability develops for providers to both build a business case, gain investment and the number of potential providers in the market increases.
Alignment with a strategic spatial plan	Has the potential to support a strategic spatial plan by providing mechanisms to deliver the distribution of assets laid out in the plan.
Conclusion	Individual system services tend to have strong locational signals through zonal tendering rounds. However, improving the coordination and visibility of tenders over the coming years would allow assets to more easily combine contracts to build a business case where there is locational correlation between service needs.

4.12 Move gate closure further ahead of real time

4.12.1 Background

- The initial design of NETA involved gate closure 3.5 hours ahead of operation. A proposal brought forward in 2001 [79] reduced that to 1 hour, arguing that it allowed greater time for supply and demand forecasts to improve and for the market to allow participants "more flexibility to balance their positions before Gate Closure" [80].
- The term Gate Closure means the time that individual assets must commit to specific operational levels through their Final Physical Notifications (FPNs) or face asset-level consequences of failing to deliver those FPNs. It is not, however, the time at which market trading can end. At present, contract volumes can be adjusted right up to the start of the settlement period, a time known as the 'submission deadline'. [81]
- Whilst late gate closure allows greater time for optimising the asset level dispatch, it reduces the time available for NESO to operate post-gate closure processes, especially the balancing mechanism. It means that large volumes of redispatch need to be identified and scheduled in a very short amount of time.
- Although it is accepted wisdom that providing the market with the maximum possible time before gate closure will optimise operation and respond to changing forecasts, the evidence to back this claim has not been reviewed. Doing so would require an analysis of how much trading is carried out in intraday markets and at what stage between day-ahead and gate closure. It may be difficult to access data on bilateral trades, however it should be possible to use power exchange data to explore the quantity of trading happening within the last few hours.
- Therefore, one solution to improve post-gate closure redispatch processes is to move the timing of gate closure and to give NESO more time for the balancing mechanism to operate once assets commit to their FPNs.
- For example, this could allow NESO to run more extensive optimisation algorithms, dispatch a significantly larger number of units, and to have time to carry out due diligence on more complex patterns of redispatch.
- The market does not balance itself perfectly. The Net Imbalance Volume (NIV) represents the net balancing actions that NESO has to take and therefore the degree to which the market itself is out of balance nationally. Data from 2019 to 2024 [82] shows that NIV varies in the range +/- 1000 MW despite the late closure of the market. An important question for this analysis is how this would increase if gate closure was moved earlier.
- Therefore, as with other elements of market design, the timing of gate closure is likely to be a balance between value from more optimal initial dispatch of assets based on the most up-to-date forecasts of operating conditions and value from greater time to more cost effectively redispatch the market outcome to manage transmission constraints.

What?	**Gate closure further ahead of real time**
Why?	The technical redispatch challenge is exacerbated by the limited time – 1 hour – available to NESO following gate closure to conduct most of the system redispatch in a coordinated way that observes many tens or hundreds of individual system constraints.
How?	Change gate closure time from 1 hour ahead of delivery to 3 or 6 hours ahead.
Locational impact?	Does not introduce a locational impact in its own right, but allows NESO significantly more time to undertake locational redispatch using the balancing mechanism as a locational mechanism. This could allow the balancing mechanism to operate more effectively with locational volume and price signals (depending on other reforms explored here).
Low cost	**+** Allows more time, which could allow control room processes to operate more effectively. There would be more time to run system studies, identify potential solutions to multiple complex constraints, reduce skip rates and redispatch assets. Overall, this is likely to put downward pressure on balancing costs. **-** Earlier gate closure reduces the ability of the market to optimise operation and to respond to close-to-real time forecast errors and unexpected faults. This could lead to larger system-wide imbalances which need to be corrected for during the period after gate closure.
Security of supply	**+** Allows greater time for NESO to solve the technical challenge of dispatching significant volumes and ensure security against numerous constraints. **<>** Moves responsibility for responding to late faults and forecast-changes from 'the market' to NESO.
Net zero	**+** Potentially provides more opportunity for NESO to access alternative actions that minimise the need to curtail renewables.
Other considerations	**Efficiency of the market close to gate closure:** a decision on whether this intervention would improve outcomes depends on the balance of improved and cheaper balancing mechanism redispatch against any loss of efficiency in the initial market dispatch. The argument often made for later gate closure is that the market is highly effective at optimising right up to delivery, for example, adjusting dispatch to reflect increasingly firm wind availability forecasts in the last few hours before delivery. However, there are aspects of system operation – such as the inability of the market to deliver a good energy balance across the GB market (something which, in theory, the market is very well set up to deliver) – which point in the other direction. Whilst earlier gate closure goes against the accepted wisdom of maximising the reach of the market in order to deliver the best outcomes, there is value in trying to understand how efficiently the market operates and to quantify these trade-offs.

Alignment with a strategic spatial plan	**N/A**
Conclusion	Providing more time to NESO for balancing mechanism-based redispatch following gate closure will relieve the technical challenge and may allow a lower-cost lower-carbon redispatch to be organised. The argument against this – that removing time for the intraday market to optimise the initial market dispatch would increase costs – appears unproven.

4.13 Improve NESO IT and control room processes

4.13.1 Background

- The NESO control room relies on a number of IT systems and both manual and automated operational processes to deliver its objectives and implement many of the principles on which system operation is based. In particular, it is responsible for maintaining an energy balance, ensuring system limits – including locational system limits such as thermal limits – are respected, ensuring there is a sufficient supply of ancillary services, and being capable of responding to secured events (e.g. a power station, interconnector or large consumer tripping off because of an unexpected fault).
- Some of the IT systems used are out of date, or do not coordinate well with each other. Many of the processes were designed for the relatively small level of balancing that the control room needed to manage during the first decade of NETA. The reliance on manual processes reflects the status of IT development when NETA was first designed. Processes often embed out-of-date assumptions about how the system operates and what types of asset will be best placed to respond, that are no longer valid.
- These issues have come to the fore as the volume of redispatch has grown and as the types of asset which can deliver services have changed. Now, it is common that within the one-hour period after gate closure, NESO needs to redispatch large volumes of generation to manage transmission constraints, and that many of the potential providers are relatively small – requiring an increased *number* of actions to deliver a particular volume of redispatch.
- There has been a vigorous debate within the sector on how to improve the control room's processes and IT systems. One driver has been the development of batteries as a provider of flexibility. These devices have often suffered from excess skip rates, where their cheaper Bids and Offers have often been ignored or 'skipped' for more expensive actions from traditional providers of balancing.
- NESO has begun to respond to this, for example, through its Open Balancing Platform programme (OBP) [83]. This began in December 2023 with the introduction of a tool for bulk-dispatch of batteries and small BMUs (which are arranged as 'zones' within the OBP) to deliver a specified aggregate need, and evidence over the past year suggests that it has increased the dispatch of these assets within the balancing mechanism [47]. During 2024, NESO has also commissioned fast and enhanced fast dispatch modules, which allow multiple assets to be dispatched at short notice, a situation which has typically required the control room to dispatch a single large asset rather than multiple smaller assets.
- One note of caution is that the debate around the improvement of balancing processes, and the solutions that have come forward to date, appear to have focused primarily on national-balancing issues. It is not clear the degree to which the locational balancing has been a focus. Whilst the ESO has reduced skip

rates for balancing actions, it is not clear how this splits between non-locational energy balancing and locational system balancing issues.

- For example, control room decision making is organised through a national balancing engineer under whom a number of zonal balancing engineers work with responsibility for particular units within a specified zone. Zones can be either geographical – and these zonal engineers will take actions to manage constraints – or technology-based with all assets of a particular technology grouped together. One stakeholder that we interviewed indicated that it is their understanding that because batteries are grouped into a single 'battery zone', they are not available to the balancing engineers responsible for geographical zones and therefore aren't normally dispatched for transmission constraints. If this is true, the approach will fast become out of date where batteries are expected to help solve transmission constraints.

What?	**Improve NESO IT and control room processes**
Why?	NESO control room relies on several IT systems and operational processes to deliver its objectives and implement many of the principles on which system operation is based. Some of those IT systems are out of date, or do not coordinate well with each other. Processes often embed assumptions about how the system operates that are no longer valid. These issues have come to the fore as the volume of redispatch has grown and as the type, and particularly the size, of asset which can deliver response has changed. NESO has begun to respond to this, primarily through its OBP. However, the initial stages appear to have focused primarily on national balancing rather than on locational issues, such as management of constraints.
How?	NESO to a) continue to invest in new IT infrastructure to support better coordination and improved control room capabilities and b) focus on improving control room processes, automating those that remain manual, and ensuring that all processes are designed for a future net zero system with a larger volume of dispatch and an increased number of small providers with a range of technical characteristics. For both elements, NESO needs to prioritise locational balancing requirements as well as national actions.
Locational impact?	The intervention doesn't inherently introduce any new locational signals or cash flows. Rather, it ensures the signals which should exist in the current system are maximised. It could increase access to the full locational volume signal, on operational timescales, that the balancing mechanism should be delivering. Improvements can ensure that all types of assets, including smaller assets and those with intertemporal constraints (e.g. storage), can be used more effectively and therefore receive stronger locational signals.

Low cost	**+** Reduces operating costs by increasing the pool of potential providers and ensuring that cheaper Bids/Offers are not 'skipped'. **+** Over time ensures a locational dependent revenue stream for locational balancing mechanism redispatch, which could lead to greater investment in assets in locations valuable for constraint management.
Security of supply	**+** Increases the potential capacity that can be accessed by the control room to respond flexibly. Over time, by maximising the potential locational signal, this will help site flexibility appropriately.
Net zero	**+** Increases access for low-carbon technologies and supports delivery of decarbonisation.
Other considerations	**Practicality:** Delivery of large-scale, complex IT systems are notoriously difficult. However, it is likely that this will be required for any market reform capable of responding to net zero. The existing OBP programme within NESO also helps mitigate practicality challenges as it shows there is both an appetite and a plan for change, which includes the development of appropriate IT infrastructure. Control room processes are themselves designed to be 'practical' implementations of higher-level principles. But existing processes were designed to be practical based on the nature of the past system and available technology. New processes should be based on current technology and should be able to improve on existing approaches. **Investability:** ensuring that more assets have clear transparent access to locational balancing revenue streams and that control room decisions are taken based on least-cost or some other clear principle, will grow confidence in investments that will rely on these revenue streams. **Market liquidity:** improvements have the potential to increase market liquidity.
Alignment with a strategic spatial plan	Likely to support a strategic plan regardless of the spatial distribution of assets laid out in the plan.
Conclusion	Improvements have been made, particularly regarding improved non-locational energy balance, through the introduction of the Open Balancing Platform. NESO should prioritise improvements to locational balancing, e.g. Bids and Offers to solve network constraints.

4.14 Introduce Dynamic Locational Transmission Loss Factors with settlement-period granularity

4.14.1 Background

- Transmission losses depend on the level of electrical resistance and current flowing on the network. They add a significant cost to the delivery of electrical energy and the contribution that different market participants make to transmission losses varies significantly with location. Losses are higher when the network is highly loaded and when electrical energy has further to travel between production and consumption. Typically, additional generation in an exporting region, which therefore increases the flow of electricity, will increase system losses, whilst additional demand in an exporting region will reduce losses.
- Transmission losses are typically circa 2% of total injected power. In 2023-4, this equated to 7.5 TWh, equivalent to approximately £700 million of energy[18].
- Today, losses are accounted for by adjusting the metered volume of energy for each market participant, a locational 'Transmission Loss Factor' (TLF). The TLF is an estimate of the average marginal losses caused by market participants within a particular zone and across a season. Zonal TLFs are calculated by using sample, representative, settlement periods from the previous twelve months. The resulting TLFs are then applied across all nodes within a zone and across all settlement periods within a season. The process splits losses between demand and generators.
- In a zone that is typically exporting, the impact of TLFs will tend to reduce the quantity of energy from market participants that is entered into settlement. This results in a cost for generators (as the amount of energy allocated to them in settlement, and therefore that they can sell, is reduced) and a benefit for demand (as the amount of energy they have to buy is reduced relative to what they physically used). In an importing zone, the impact is the opposite.
- TLFs can vary significantly across the country and can introduce up to a 7% difference between north and south during winter[19] as shown in Figure 9. That means for 1 MWh of electricity generated in North Scotland, only 0.96 MWh can be sold whilst 1 MWh generated in South-West England allows 1.03 MWh to be sold. in

[18] Transmission losses from [86]. Financial value calculated from average day ahead wholesale prices as listed in the Capacity Market Intermittent Market Reference Price data [87].
[19] Value derived from winter TFLs for 2022 available [88].

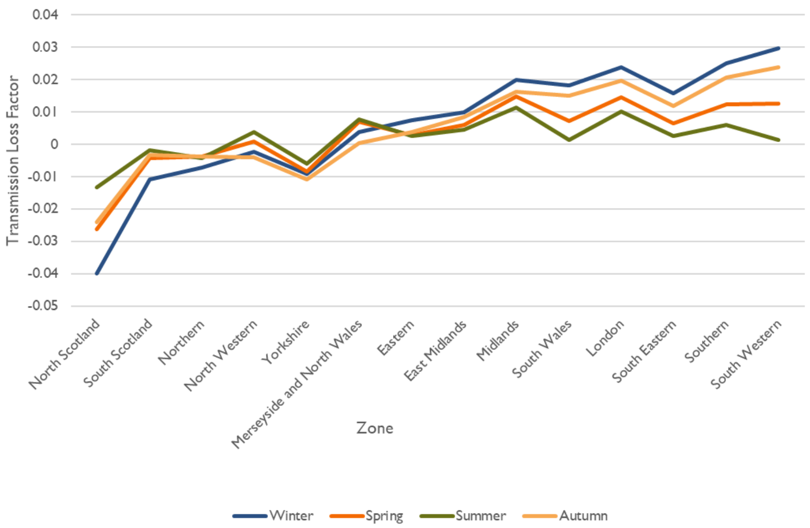

Figure 9: Transmission Loss Factors for 2022. TLFs adjust metered volumes – a number less than zero means a reduction in metred volume and a number higher means an increase in volume. For example, for winter Northern Scotland volumes will be reduced by 4% of metered whilst volumes in the South-Western (England) zone will be increased by 3%.[20]

- The result is that all assets in a particular zone receive a fixed TLF valid for all settlement periods in a season. As these are based on an *ex-ante* calculation using historical data, they do not reflect actual conditions. The low temporal granularity means that they don't reflect how losses change settlement-period by settlement-period. One result is that, for example, a schedulable generator in a region with a large wind fleet that typically only runs during periods of low wind will receive a negative TLF for all of its output. However, if it is typically only operating when the wind isn't blowing, it is likely to be reducing imports into that zone and, therefore, *reducing* transmission losses.
- Interconnectors are exempted from TLFs: volumes traded and the physical flows on interconnectors are not adjusted to reflect losses.
- The current approach is not the only option for the calculation and use of TLFs. For example, they could be calculated *ex-post* from outturn data, and calculated separately for different settlement periods rather than on an average seasonal basis. The table below explores that option.

What?	**Introduce dynamic, locational transmission loss factors by calculating a separate TLF for each zone and for each settlement period *ex-post* using outturn data.**
Why?	Loss factors are currently static for all settlement periods throughout a season and are calculated *ex-ante* using historical data. They don't reflect the outturn operating conditions of individual assets, including the significant difference in an asset's contribution to losses during different settlement periods.

[20] Graph derived from data provided through Elexon Portal [88].

How?	Calculate TLFs separately for each asset and each settlement period *ex-post* using outturn data or *ex-ante* based on day-ahead or intraday forecasts.
Locational impact?	Introduce a dynamic locational volume signal on operational timescales by adjusting the volume of energy that is used for settlement, which affects a wide range of revenue streams, including wholesale sales, support mechanism payments and the balancing mechanism. The signal will be seen by generation, demand and flexibility and will act as a volume-based incentive to encourage or discourage operation at particular times and places. The uncertainty over future TLFs and the impact on revenue may create a locational uncertainty signal for investors. And if TLFs are difficult to forecast even a few hours ahead of operation, it will create an uncertainty signal even on operating timescales.
Low cost	**+** TLFs become more cost-reflective of the specific conditions of a particular plant in a particular settlement period, potentially driving dispatch decisions which lower transmission losses. **-** Difficulty in forecasting TLFs, and risks associated (particularly with models which set TLFs *ex-post*) are likely to lead to increased risk-premia.
Security of supply	**<>** The reform would be unlikely to have a strong impact on security of supply.
Net zero	**+** Minimising system losses reduces the total quantity of generation required. **-** Renewable generators are likely to see the biggest impact of a change such as this because of their spatial and temporal correlation (when they can generate, they are also likely to contribute most significantly to losses because many other generators in the same area will also be able to generate), this combined with the increased uncertainty / risk would likely add an extra challenge for investability or an increase in cost of capital.
Other considerations	**Practicality:** likely to suffer many of the same problems identified for cost-reflective BSUoS by the BSUoS Task Force: dynamic TLFs would be difficult to forecast, create increased risk for market participants, with that risk hard to mitigate. This could lead to the same conclusion as for BSUoS: dynamic TLFs are unlikely to be effective at delivering a practical locational signal. If implemented, there are several options for how and when TLFs would be calculated which would need to balance accuracy (which would be better using an *ex post* approach) and the ability of the market to respond (which would be better using an *ex ante* approach). **Investability:** see above – likely to be adversely affected.
Alignment with a strategic spatial plan	As this has the potential to add additional costs and risks to renewables, and particularly those renewables in areas where a strategic plan is likely to require them, there is a risk that this will accentuate existing locational investment signals delivered through the static TLF process.
Conclusion	There are significant implementation challenges for dynamic TLFs and it is uncertain how effective the intervention would be. This

	would depend on the ease with which market participants would be able to forecast TLFs. The approach is likely to suffer similar challenges to those identified for dynamic, locational BSUoS.

4.15 Expose interconnectors to a locational shadow price

4.15.1 Background

- Interconnector dispatch is currently set almost entirely by the wholesale energy price differences between the connected markets. For some interconnectors, this is the day-ahead market price only, for others it allows adjustments to reflect intraday markets. However, everything is based on wholesale energy prices.
- Interconnectors are also exempted from existing locational signals. They do not pay TNUoS charges [84] , and their injections or withdrawals of power from the GB system are not adjusted by transmission loss factors [85].
- These anomalies have been driven by EU rules and by the different treatment of interconnectors in many European markets. The network links between most countries in Europe are typically part of the AC network, with power flows emerging from the laws of physics rather than by explicit dispatch. These links are also typically owned and operated by the Transmission System Operators (TSOs), entities which combines the roles of GB's NESO and Transmission Owners. Whilst GB interconnectors are HVDC (rather than AC) and can be explicitly dispatched with flows set independently of other dispatch decisions, and are independent, privately owned commercial profit-making ventures, their regulation and integration into the EU reflected the characteristics of cross-border network capacity in Europe.
- Brexit has led to the UK leaving the EU Single Market. This led to a reversal of many of the developments for more efficient interconnector trading that occurred over the past decade. In particular, the majority of GB interconnectors which had been run via implicit arrangements at day-ahead stage where interconnector flows were set by a centralised algorithm based on price differentials between countries have since been forced to revert to explicit auctions for nomination of flows.
- The Trade and Cooperation agreement [29] has committed the EU and the UK to aim for a form of 'volume coupling' (rather than the full price coupling involved in implicit auctions before Brexit).
- Overall, Brexit is both a risk and an opportunity. Outside of the European single energy market, it may be possible to implement some locational signals that would not have been possible within it. For example, it may be possible to charge interconnectors TNUoS and adjust their flows by TLFs.
- However, there is a risk that changes that diverge from the EU's 'target model' would make it harder to trade in the near term, and more difficult to re-integrate in the future, if such a decision were made.
- EU rules, complications emerging from Brexit, and a lack of transparent redispatch arrangements for NESO to use with interconnectors mean that it is challenging to move the basis of interconnector dispatch away from wholesale prices.

- If the decision is to retain a national wholesale price in GB, it would therefore naturally still be the case that interconnectors would not receive an appropriate locational dispatch signal and will continue to dispatch based on the difference between the national GB price and the price at the far end, regardless of whether that exacerbates or relieves an internal GB transmission constraint. Recent analysis identifies interconnectors as a leading cause of the inefficiency in the current market, and one of the key reasons for changing to zonal pricing. LCP Delta's most recent analysis, for example, suggested that the impact could be as much as £11 billion over 20 years. This analysis also suggests that delivering more effective dispatch/redispatch of just 25% of interconnector capacity could reduce the benefit of zonal pricing from £11 billion to £3 billion over 20 years [7].
- One approach, suggested by Frontier Economics [10], is to find a mechanism to expose interconnector trades to the type of locational signal that they would see in a zonal market, without affecting other assets. This would use a regulated mechanism to adjust the 'net' revenue that an interconnector trade would receive across both its wholesale energy market trading and an additional regulated levy or payment.

What?	**Expose interconnectors to a locational shadow price**
Why?	Provide a locational energy-based signal to interconnectors as one of the key contributors to constraints, and to overcome the fact that interconnectors are exempt from many of the existing locational signals.
How?	Apply an *ex-post* levy or payment to interconnector imports / exports equal to the difference between the wholesale energy price and a calculated locational shadow price.
Locational impact?	Introduce a net-locational price signal on operational timescales which would affect net-expected price and uncertainty to interconnector trading. The signal would devalue interconnector imports behind an internal GB export constraint and interconnectors exports in-front of an internal GB export constraint. It would incentivise market-participants trading over interconnectors to forecast and respond to the net impact of wholesale energy cash flows and levy/payment in a similar way to the way they would respond to full locational pricing. However, it would not apply non-firm access to interconnectors and, therefore, would not introduce a locational volume signal in the same way as full LMP (nodal or zonal).
Low cost	**+** Encourage interconnector flows to respond to forecast transmission constraints when self dispatching, therefore reducing constraint costs. This could impact on both turn down and turn up elements. **-** Affect the investment case for new interconnectors, leading to higher prices in the long term which would now depend on (a) the expected *net* differential between GB (wholesale price +/- adjustment) and the connected market. However, it could also make the project less investable because of the increased

	regulatory risk. If this led to delayed or abandoned investment could lead to higher overall costs.
Security of supply	**+** The mechanism has the potential to reduce the cost of securing the system through redispatch.
Net zero	**+** Reduce the need to curtail wind by ensuring interconnectors are dispatched in a way that considers and helps resolve constraints at the initial dispatch stage.
Other considerations	**Practicality:** requires set up of a zonal model to calculate zonal shadow prices. It will be important to consider how / who forecasts constraints, what is published and when by NESO. There may be options available to set shadow prices *ex-ante* based on day-ahead or intraday forecasts of constraints rather than *ex-post* in order to increase confidence. **Alignment with TCA:** The TCA commits the UK to retain the current position that there are no network charges on individual transactions across electricity interconnectors. The risk of incompatibility with the TCA is significant and may require renegotiation of its terms. This is both politically challenging and makes deliverability of the reform uncertain.
Alignment with strategic spatial planning	Intervention could provide a locational signal for new investment in some locations, but the calculation is challenging: it is not the absolute average impact of the levy / payment, nor even the variability of the levy / payment, but the differential between the sum of the GB wholesale price +/- the levy on one side and the wholesale price in the connected market. As noted above, additional regulatory risk across the several decades of operation could also impact on investability.
Conclusion	Theoretically, this intervention can deliver a locational price signal to interconnectors whilst leaving other assets facing the national wholesale price. However, it is likely to face significant practical challenges, create significant barriers to market participants trading across interconnectors, including regulatory risk arising from uncertainty over how such a system might be 'tweaked' in the future. It is likely to struggle to align with the Trade and Cooperation Agreement and European Internal Energy Market rules, as such, there may be limited value in developing the idea further.

4.16 Develop new SO-SO frameworks for pre-gate closure trading

4.16.1 Background

- Within GB, NESO undertakes some pre-gate closure trading across some interconnectors.
- The principle for this activity is that NESO trades following the results of the day-ahead auctions with *market participants,* i.e. those entities which have purchased capacity on the interconnectors and nominated it to flow.
- At day-ahead stage, they a) held and nominated capacity on the interconnector; b) bought energy in the 'from' market; c) sold energy in the 'to' market.
- Where NESO agrees a trade with a market participant, the mechanism to adjust the overall flow of the interconnector is down to that market participant. They a) sell back energy in the 'to' market, b) buy back energy in the 'from' market'; c) adjust the interconnector nomination.
- This approach is only possible on interconnectors which have both day-ahead and intraday trading and use explicit rather than implicit dispatch.
- This limits its use to interconnectors connecting to France, Belgium, Netherlands and Denmark. The Norwegian interconnector uses implicit trading and currently only runs a day-ahead auction. The Irish interconnectors also use implicit trading and only use intraday auctions.
- Adjustments on the Norwegian and Irish interconnectors tend to be limited to regulated or balancing approaches, such as the use of Net Transfer Capacity (NTC) limitations or the Cross Border Balancing.
- There is another downside which is that a countertrade with a market participant does not prevent other market participants from continuing to trade in the intraday market up to gate closure, potentially reversing the effect of the NESO countertrade.
- By contrast, at least some TSOs in Europe use a principle which redispatches the interconnector through trading conducted more openly in the market by the TSO itself.
- For example, TenneT and Energinet collaborate on redispatching the German / Denmark DK1 boundary following the day-ahead dispatch [86]. The process is as follows:
    1. TenneT identifies a redispatch need in Germany which is often driven by a combination of excess wind generation in Northern Germany, significant flows into Germany from Denmark, and a transmission constraint between north and south.
    2. They then estimate the cost of managing that redispatch within Germany.
    3. Next, they ask Energinet to sell energy on the DK1 intraday market, where those trades can be made at a lower price than the internal German redispatch.
    4. Energinet makes the trades and passes the cost to TenneT.

5. As the border is an AC border, the flows from Denmark to Germany, and hence the internal German constraints automatically reduce relative to the day-ahead dispatch.

- Similar approaches can be used, with a slight adjustment, for GB HVDC interconnectors and can be accommodated within both explicit and implicitly traded arrangements.
- The reform proposed here is that NESO should work with connected TSOs to explore the opportunity to develop open, transparent, market-based redispatch mechanisms between day-ahead and intraday timescales, which can more cost effectively reduce constraints.
- One of the current authors has published a more detailed description of this approach in a report for Scottish Renewables [28].

What?	**Develop new SO-SO frameworks for pre-gate closure trading**
Why?	Current NESO countertrading with market participants is opaque, ad hoc and limited to explicitly traded interconnectors with day-ahead and intraday auctions (those to France, Belgium, Netherlands, and Denmark).
How?	NESO would develop a formal framework with connected TSOs for countertrading: following day-ahead dispatch of interconnectors, NESO would ask the connected TSO to trade in their own intraday market to reduce / increase flows to match NESO redispatch needs. This trading would be subject to a maximum / minimum price, which would reflect the likely alternative – the cost of redispatch of GB assets through the balancing mechanism. The connected TSO would pass the costs back to NESO (this follows the German/Danish example). Once trades are agreed, NESO liaises with the interconnector owner to adjust the physical flow.
Locational impact?	The intervention creates a clear locational redispatch mechanism for interconnectors at intraday stage based on internal GB constraints and does so in a market-based way that accesses resources in connected markets where and when they are cheaper than the equivalent action from GB assets. The intervention provides clear locational price and volume signals and an appropriate mechanism for interconnector redispatch in line with GB transmission constraints.
Low cost	**+** Allows NESO, via the connected TSO, to access resources for redispatch in connected markets where this will be cheaper than equivalent GB action. **+** Removes the risk that exists under current NESO to market participant countertrading, that once an intraday adjustment is made, that other market participants may reverse the adjustment.

	+ German / Danish experience suggests that intraday market trading is cheaper than relying on balancing timescale cross-border redispatch options. **-** Does not deal with the initial dispatch, only the redispatch
Security of supply	**+** Reduces the cost of securing the system through redispatch and provides a mechanism to redispatch all interconnectors intraday (rather than only the channel interconnectors).
Net zero	**+** Provides a route to redispatch interconnectors rather than turn down renewable generation or turn up inefficient fossil fuel peaking plant.
Other considerations	**Co-development with connected TSO:** any framework needs to be co-developed with stakeholders in the connected market and delivered in collaboration with the connected TSO. Mechanisms therefore need to consider the value they create for the connected TSO such as greater visibility of redispatch actions from NESO and the ability to use the mechanisms to solve issues within the connected system. **Investability/liquidity:** the approach should not affect interconnector investability and should increase the liquidity of redispatch by increasing the pool of providers to the connected market**.** **TCA/Internal Energy Market considerations:** the proposed model is based on arrangements between Germany and Denmark which have received EU approval. It is based on transparent and open market trading and therefore fits with both GB and European emphasis on using markets as the first choice of mechanism. It gives improved visibility to and involvement of the connected SO, and it is a mechanism that can operate in both directions, allowing the GB system to support connected markets and vice versa.
Alignment with strategic spatial planning	The intervention is compatible with the strategic plan.
Conclusion	There appears to be significant potential for the NESO to work proactively and cooperatively with connected System Operators to deliver a more transparent and predictable trading framework utilising (NE)SO to SO pathways (rather than the current NESO to market participant pathway). There is an apparently successful example operating within European IEM rules between Germany and Denmark.

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