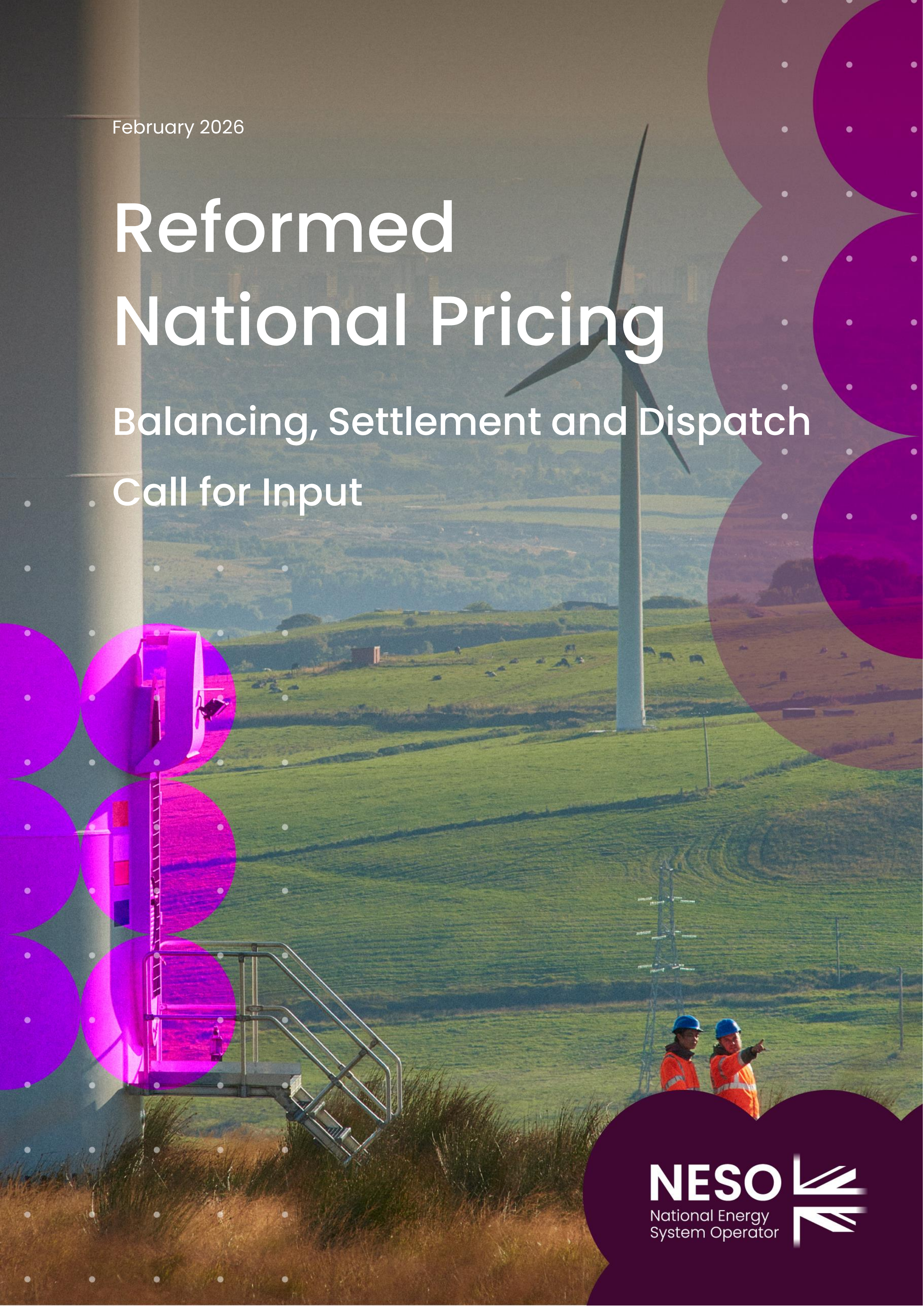

February 2026

Reformed National Pricing

Balancing, Settlement and Dispatch

Call for Input

NESO
National Energy System Operator

Contents

Foreword

Welcome to NESO's Call for Input on the balancing, settlement and dispatch reforms being considered by the Government's Reformed National Pricing programme.

As an industry we have made great progress towards decarbonising the electricity system. The overall proportion of renewable power has been increasing year-on-year and reached 44% in 2025 (127 TWh), representing a threefold increase since 2015. This has shifted the diversity and location of generation on the system. Alongside this, further interconnection, the deployment of battery storage, and active demand participation are all playing a key role in keeping the system balanced. These changes in the operating environment mean the way we must operate the system today has fundamentally changed.

This period of rapid transformation is set to continue as our generation and demand mix evolves at pace. However, our market arrangements have not kept pace with these changes and therefore reform is required to ensure that consumers and industry get the maximum benefits from our changing system. The Review of Electricity Market Arrangements (REMA) was established in 2022 by the Government to deliver enduring market reform that will deliver a secure, sustainable and affordable energy system.

In July 2025, the Department of Energy Security and Net Zero (DESNZ) announced its decision to set up the Reformed National Pricing (RNP) programme in its REMA Summer Update. This includes progressing an ambitious set of reforms that will promote the efficient siting of new assets, reduce the impact of constraints and drive efficient operation of the system. In our role as independent, impartial advisors, we at NESO have supported DESNZ and Ofgem throughout the REMA process and will continue to help define and develop the RNP recommendations ahead of decisions later in 2026.

RNP represents an opportunity for us to reform electricity markets to better utilise our energy resources, provide the market with clearer signals and incentives, improve data quality and granularity to promote more innovative use of technology, and ultimately operate the system in a more efficient and cost-effective way.

This Call for Input outlines the proposed balancing reforms and introduces our further work on dispatch reform options. While delivering large scale reforms presents many opportunities, it can also be disruptive. We recognise that whilst consumer value is at the heart of these proposals, as a package these reforms represent significant transformation which will impact many organisations. We are seeking your engagement and collaboration on the proposed reforms, to ensure that we collectively move forward with a package that benefits consumers, promotes competitive markets, optimises system operations and encourages investment.

Therefore, I encourage you to share your feedback, insights and evidence, so that we can collectively progress to decision and implementation on the strongest footing.

Rebecca Beresford
Director of Markets

Executive Summary

Great Britain's (GB) electricity system is undergoing a profound transformation, from a system characterised by a small number of large thermal generation assets with relatively predictable demand, to one with large volumes of weather-dependent generation with fast acting, flexible assets, active demand participation, and greater interconnection. However, our network infrastructure and market arrangements have not evolved at the same pace, leading to NESO increasingly intervening in the market to ensure supply and demand is balanced, and maintain system operability.

In 2022, the Government launched REMA to assess options for reforming the GB electricity market to deliver a low-cost, secure, and decarbonised electricity system. The REMA programme considered a range of options before publishing its policy outcome to progress RNP in its REMA Summer Update in July 2025.

The RNP package retains the single national wholesale price in GB and introduces a series of reforms to market arrangements to help to deliver a more efficient, secure, and affordable clean power system. The package is built around three interlinked pillars.

Reform siting and investment levers

Aligning siting and investment levers across the power system behind the Strategic Spatial Energy Plan (SSEP), to incentivise the location of new assets in optimal areas, in a way that achieves the best balance between the roles of greater strategic planning and markets

Focus of this Call for Input

Improve system operability and efficiency

Reducing the cost of running the power system in real-time, by reforming balancing and settlement arrangements, considering the potential for further dispatch reforms

Further bear down on network constraint costs

Additional action across our power system to further bear down on both the volume and cost of network constraints, including ahead of 2030

This Call for Input sets out the principles and challenges for balancing, settlement and dispatch reform to address. The RNP balancing and settlement reform (hereafter "balancing reform") package is introduced, and we outline initial implementation considerations alongside high-level impacts on industry bodies and market participants. This is followed by a discussion of dispatch arrangements and potential options for further reform, which may be necessary to meet the required levels of system operability and cost efficiency.

Following the publication of this Call for Input, DESNZ will soon be publishing its RNP Delivery Plan. This will set out in more detail the siting and investment levers and constraint management action plan pillars, and the next steps on further policy development and the delivery of the RNP package.

Reformed National Pricing: Balancing and Dispatch Reform

Vision

Our vision for RNP Balancing and Dispatch reform:

Balancing and dispatch arrangements that support a secure and cost-effective clean power system, efficient investment, and provide enduring value for consumers.

Challenges

To achieve this vision, our balancing and dispatch reforms must address four key challenges. These challenges are how we have structured our thinking when assessing the impacts of the balancing and dispatch reforms.

Challenges to address

Operability and cost challenge from increasing redispatch
The volume of balancing actions and costs are expected to increase and remain at historically high levels, driven to a large extent by network congestion, requiring significant market intervention from NESO to balance the system.

Insufficient visibility of, and access to, balancing resources
Rapidly increasing volumes of embedded generation that are largely not visible and not accessible to NESO for balancing. This results in higher levels of uncertainty for operating the system, higher costs from inefficient actions and reduced market liquidity.

Overlap between the wholesale market and balancing
Overlapping timeframes and conflicting signals between the wholesale and balancing markets can result in unnecessary and inefficient balancing actions. This also leads to a distorted imbalance price which impacts market participants' forecasts and trading.

Distorted wholesale price signals, and incentives to exacerbate system constraints
Increasing redispatch volumes along with high and predictable network congestion increases the risk of strategic positioning against constraints.

The volume of redispatch actions is expected to increase and remain at historically high levels, driven to a large extent by network congestion. In the last six years alone, annual network congestion volumes have grown around 170%, from 5 TWh in 2018/19 to 13.5 TWh in 2024/25. To manage this, NESO redispatch actions at times account for over 50% of national demand. Looking forward, increasing redispatch will require even more significant intervention from NESO to unwind self-dispatch positions to balance the system and maintain system security.

Consequentially, the scale, complexity and cost of NESO's actions into the market to secure the system has grown, and will continue to grow, such that we are no longer the residual balancer as intended under the current market arrangements.

As a result, annual balancing costs totalled £2.7bn in 2024/25 and are projected to reach approximately £4-8bn in 2030, with the size, timing and duration of the peak in balancing costs dependent on the delivery of new network build (and in the absence of market reform).

NESO's ability to meet increasing operability challenges depends on how closely the wholesale market position is aligned to the needs and capability of the system, and to what extent tools and resources are available to realign the two. The further the market is from an operable position, the greater the redispatch required. With greater redispatch required, it is more complex to find viable solutions across multiple interacting system needs in short timescales.

NESO has made significant progress in recent years to manage increasing system complexity through enhanced capabilities. However, the projected increase in redispatch requirements poses several operability challenges and inefficiencies.

This includes relying significantly more on interconnector redispatch to manage system constraints than we do today; uncoordinated scheduling of flexible assets exacerbating constraints in unpredictable ways; and complex interactions between wholesale and ancillary services markets, adding costs to consumers.

Despite higher redispatch volumes, NESO has less visibility of, and access to, balancing resources as the proportion of small, distribution connected assets grows. Approximately 33 GW (or >75%) of distributed energy assets are not visible to NESO or accessible for balancing in real-time, creating operational challenges. This is resulting in higher levels of uncertainty and variability when operating the system.

If NESO does not know what units are planning to do, this increases operational risk, and it is likely that inefficient actions would take place resulting in higher balancing costs. Without sufficient access to balancing resources in real-time, this limits our ability to resolve complex operational issues and removes opportunities for balancing resources to be efficiently utilised.

Assets outside the Balancing Mechanism (BM) could be responding to price signals in real-time, which can often counteract or compete with NESO actions, resulting in poor coordination between wholesale and balancing markets, at further consumer cost.

Meanwhile, more flexible, price-sensitive assets (including demand) and a renewable, Battery Energy Storage System (BESS) and interconnector-led generation mix is leading to faster changes in generation and demand profiles. These assets are responding in real time to operational signals and rules which do not adequately reflect balancing needs, necessitating additional action by NESO and creating large swings in the system frequency.

To operate the system in an efficient, coordinated and economic manner, NESO must manage and consider impacts of redispatch actions across current and future periods to minimise total system costs and ensure system security. With a greater need for proactive action and increasing limited-duration energy storage assets on the system, this introduces challenges for intertemporal optimisation which the BM, as a redispatch market, is not designed for. This can result in inefficient use of resources and missed revenue opportunities for market participants.

Lastly, the inconsistency between the national wholesale price and locational balancing in real-time, coupled with the scale and predictability of congestion, create the incentives and information for market participants to strategically position themselves against constraints. In turn, market participants could obtain undue revenues through strategic positioning in the wholesale market around network constraints. If present, this behaviour leads to distortions in the wholesale and imbalance prices, which could result in inefficient investment in energy assets and higher costs for consumers.

RNP Balancing Reforms

NESO has considered a wide range of reform options over multiple years and engaged with industry through a series of stakeholder events. This engagement has supported our understanding of the challenges with the current market arrangements, and the potential impacts of reform on market participants.

The proposed balancing reforms have been identified with DESNZ and Ofgem to improve the operational efficiency of the system under a national price wholesale market with self-dispatch arrangements. An introduction to these reforms, and how they meet the above challenges, is provided below.

Reform 1 - Lower the mandatory Balancing Mechanism participation threshold

This reform would lower the mandatory threshold for participation in the BM. It would increase NESO's visibility of and access to balancing resources which should lead to better coordination of resources to meet system needs, lower balancing costs through more efficient dispatch and increased competition, and increased system security.

Smaller market participants, such as Distributed Energy Resources (DERs) and Consumer Energy Resources (CERs), would gain access to BM revenue opportunities, but would also face new registration, compliance, and operational costs. Hence, consideration must be given to ensuring BM requirements are fit for purpose for smaller market participants. This change may incentivise aggregators to play a bigger role in managing smaller assets in the BM. An enduring Transmission System Operator (TSO)-Distribution System Operator (DSO) coordination design would need to be accelerated, including definition of operational and flexibility markets interactions and rules, to ensure efficient whole-system optimisation. Initial assessment suggests a phased reduction of the threshold starting in 2027, ultimately targeting a threshold of 1 MW (subject to further assessment).

Reform 2 - Align market trading deadline and Gate Closure

This reform would realign the market trading deadline to BM Gate Closure, reversing Balancing and Settlement Code (BSC) modification P342. Currently, the market trading deadline is at the start of the Settlement Period (SP). Realigning this with Gate Closure aims to provide more certainty on the actions required post-Gate Closure, as wholesale market trading and NESO balancing actions are no longer occurring simultaneously. Market participants would need to finalise trades by Gate Closure, requiring better forecasting due to higher imbalance risk. This may reduce near real-time market liquidity and require updates to trading systems. Initial assessment suggests implementation starting in 2027.

Reform 3 - Final Physical Notifications match traded position

This reform would require market participants to match their market traded position with their Final Physical Notification (FPN). This would prevent market participants from intentionally taking an imbalanced position at Gate Closure to benefit from exposure to the imbalance price, removing the risk that NESO takes actions based on FPNs that do not reflect the market traded position. In addition, ahead of Gate Closure, aggregated traded positions would be made visible to NESO to provide a better forecast of the upcoming market position, or where to expect that PNs might change as the market trades out an imbalanced position.

For market participants, this requires closer alignment of physical and traded positions, incentivising better forecasting and scheduling, but reduces their flexibility to respond to changing system conditions close to real-time. Compliance monitoring would be required, with potential for further enforcement measures to be applied to market participants. Initial assessment suggests implementation starting in 2027. Unit-bidding would facilitate a more effective implementation of this reform.

Reform 4 – Unit-level bidding

This reform would require market participants to provide unit-level bids and offers in the day-ahead and intraday markets, instead of the portfolio-level participation that exists today, associating economic offers in these markets with specific units. This reform would support requiring FPNs to match traded positions, facilitate scheduling enhancements and increase transparency to better support Ofgem and NESO's investigation of behaviour that exploits inefficiencies in the market.

This is a significant reform which adds complexity to the market arrangements and may have significant transition costs, especially for those market participants with diverse portfolios. Implementation timescales will be assessed following the Call for Input.

Reform 5 - Shorter Settlement Period

This reform would reduce the SP length to 5 or 15 minutes, to provide better temporal price signals to market participants to resolve energy imbalances. Shortening the SP provides a more granular imbalance signal, incentivising more shape in market parties' trading to better match the demand curve and other behaviours, like fast ramping of interconnectors, BESS and demand-side flexibility.

A shorter SP would benefit fast-responding assets by revealing the value of flexibility to the wholesale market but increases volatility and data requirements. This is a significant reform impacting processes and systems across the industry and expected to have significant transition costs. Initial assessment suggests a phased implementation approach prioritising wholesale and large consumers, with retail consumers (i.e. domestic and small business) initially being profiled until metering changes can be implemented. Timescales will be assessed following the Call for Input.

Summary of our assessment of the balancing reform package

The impact of the proposed balancing reforms is based on our qualitative assessment of the package, which will support the next stage of policy development. We invite stakeholders to share their views on our assessment to ensure all relevant impacts are correctly captured.

The net impact of the proposed balancing reforms, however, is an empirical question to be assessed in the Cost Benefit Analysis (CBA), which will be supported by an impact assessment and implementation assessment to ensure the recommended package is robust and evidence-based, and impacts on all market participants are considered.

We have summarised the theorised impact of the reforms against the balancing and dispatch challenges below. However, there are several factors which could impact this assessment. This includes the exact design of the reform, the timing of implementation, and interactions between the reforms that may not be fully captured here.

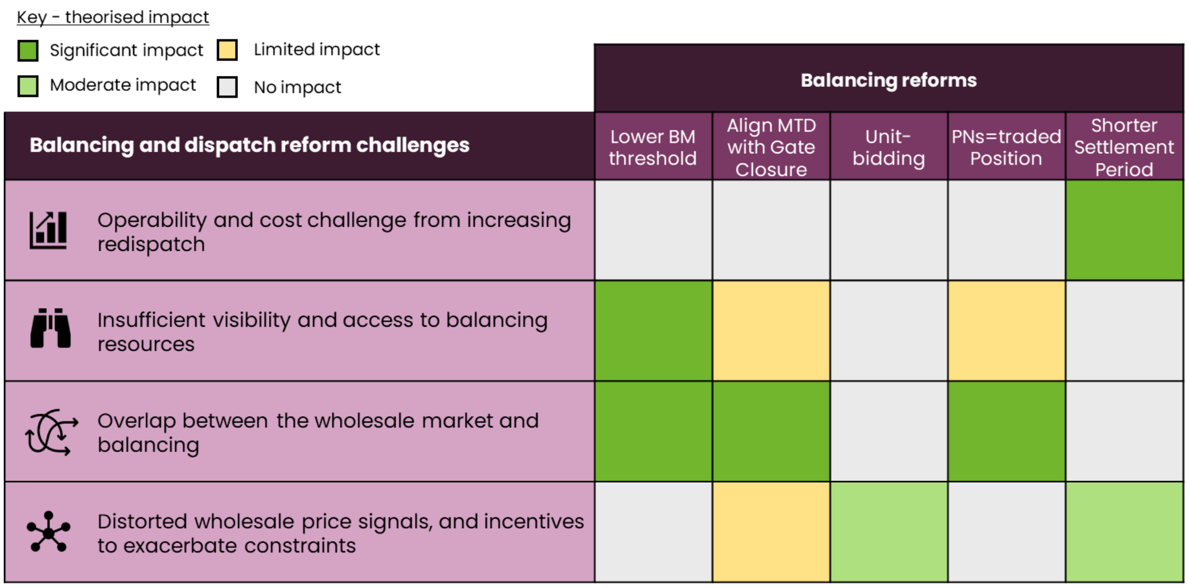

Figure 1: *Impact of the balancing reforms against the challenges*

We observe that the package is most effective against:

- Insufficient visibility and access to balancing resources
- Overlap between the wholesale market and balancing
- Distorted wholesale price signals, and incentives to exacerbate constraints

However, there are some gaps within the remaining challenge:

- Operability and cost challenge from increasing redispatch

While a shorter SP could have a significant impact on energy balancing, it only addresses the temporal value of energy, not the locational value of energy, which is the key driver of redispatch actions. Similarly, a lower BM threshold would enable more efficient optimisation of balancing resources, but it largely addresses *how* we manage high volumes of redispatch, rather than reducing the volume of redispatch required.

The volume of redispatch projected under national pricing would necessitate significant NESO intervention into the market by unwinding self-dispatch positions to maintain system security. This is likely to be significantly challenging and inefficient, in turn having a direct impact on consumer bills.

Reforms to balancing arrangements alone cannot address the underlying cause of high redispatch volumes – that is the level of network congestion that is projected to remain in the system. Nevertheless, such reforms are required to ensure the risks of such high volumes of redispatch can be managed securely and efficiently.

Dispatch Reform

As well as the above balancing reforms, we are continuing to explore a range of other dispatch reform options with DESNZ and Ofgem with a view to improving system operability and reducing costs for consumers. Dispatch reform would complement the balancing reforms and provide wider benefits across all the challenges, with a particular focus on improving system operability and meeting the cost challenge from high levels of redispatch.

Dispatch reform could help to address this challenge by creating earlier alignment between the market position and the needs of the system, reducing the need for redispatch close to real time, which in turn decreases consumer costs.

To be clear, any reform to dispatch arrangements must satisfactorily address a number of key requirements, including delivering benefits for consumers, ensuring future system operability, maintaining investor confidence, and ensuring compatibility with the Government's legal obligations and international agreements.

Further work on dispatch reform will be undertaken in 2026, utilising the feedback received from this Call for Input.

What Next?

Your input is key to us collectively achieving the best outcomes from the market reforms and we would like to thank you in advance for your time and effort in providing us your feedback.

Your responses will be used to help shape the final design and implementation of the reforms. In addition, we invite stakeholder suggestions on other reform options that have not been considered, and which could help address the balancing and dispatch reform challenges.

If your organisation operates across multiple market roles, you are welcome to provide multiple responses or to provide one consolidated response.

We will be holding a webinar during the response period in March 2026, to discuss the Call for Input and provide an opportunity to answer your questions. Please check our website for details.

Please provide all feedback via the response proforma by 5:00 p.m. on Tuesday 14th April 2026.

Responses may be shared with DESNZ and Ofgem as our partners in the RNP programme. Responses may also be shared publicly. If any part of your response is confidential and should not be published, please indicate this in your response.

After the publication of the Call for Input our next steps are as follows:

1. Call for Input Webinar in March 2026
2. Review Call for Input responses, which will help inform the CBA, impact assessments and implementation planning
3. Provide recommendations to support decision making process in the second half of 2026.
4. Alongside the work above we will continue to assess the options for dispatch reform considering the feedback from this Call for Input.

Opportunities for engagement after the Call for Input will be provided to ensure the CBA, impact assessments and implementation planning can be comprehensively assessed. More information on this will be shared on our RNP programme webpage.

For any questions or clarifications, please contact **box.market.strategy@neso.energy**.

1. Introduction

1.1 Background

The electricity system in GB is undergoing a profound transformation. Over the last two decades, we have transitioned from a system characterised by large, thermal generation and regular patterns of demand to one with increasing volumes of weather-dependant generation and fast-acting, flexible demand. Our technology mix is becoming more diverse, with generation and demand actively participating in the market at all levels of the network, while we become increasingly interconnected with neighbouring countries.

NESO and industry have collectively delivered improvements to the market arrangements to adapt to these challenges. However, an even greater rate of change will be required to achieve (1) the Government's mission of Clean Power by 2030 and (2) a fully decarbonised GB economy by 2050.

A successful transformation to clean power and beyond requires an enduring market design that can adapt to the coming change and enable the most efficient utilisation of all assets across the network. This must balance ensuring security of energy supply; minimising costs for consumers; and the decarbonisation of the economy.

Review of Electricity Market Arrangements

REMA was launched in 2022 by the Government to identify, assess, and implement options for reforming the GB electricity market arrangement to deliver a low-cost, secure, and decarbonised electricity system.

The REMA programme considered a range of options to meet a number of objectives including passing through the value of a renewables-based system to consumers, ensuring investment in new renewable generation, moving to a flexible and resilient decarbonised system, and operating the system efficiently.

In July 2025, the Government published the REMA Summer Update which set out the policy outcome for REMA. Two broad approaches were considered for wholesale electricity market reform:

- Zonal pricing, where the electricity market would be split into several zones to reflect the most significant (but not all) network congestion; or
- Reformed National Pricing (RNP), which would retain a single national price, alongside reforms to balancing arrangements and a greater emphasis on strategic planning.

The Government concluded that they would pursue RNP, and therefore not introduce zonal pricing. As part of RNP, the Government committed to implementing a range of reforms to the existing arrangements and committed NESO to launch a consultation on balancing reform, which is the main objective of this Call for Input.

1.2 Reformed National Pricing package

The RNP package is a combination of reforms designed to modernise the GB electricity market, ensuring it can deliver an efficient, secure, and decarbonised power system. The package is built around three interlinked pillars.

1) Reform siting and investment levers to deliver the Strategic Spatial Energy Plan

- The Strategic Spatial Energy Plan (SSEP) and associated levers, including reforms to Transmission Network Use of System (TNUoS) charges, are intended to provide stronger locational investment signals.
- These reforms focus on incentivising new assets to connect in optimal locations to minimise system costs and reduce impacts on transmission network constraints.
- By improving locational signals for investment, the market can better align new generation and demand assets with network capacity, supporting long-term system efficiency. On its own, efficient siting of resources does not result in efficient operational decisions.

2) Improve system operability and efficiency

- The reforms to balancing arrangements target improvements to the operational efficiency of the system to ensure supply and demand is balanced in a cost-effective and secure manner.
- These proposed reforms aim to increase the efficiency of operational signals in the market, improve NESO visibility and access to balancing resources, create a clear handover of balancing responsibility, and facilitate a fair and transparent market.
- Further dispatch reform may be required to deliver the RNP objectives in full. We explore this in more detail in Section 5.

3) Further bear down on network constraint costs

- The constraint management element of RNP aims to support and coordinate reforms and workstreams that reduce the volume and cost of managing network constraints.
- It involves various initiatives to increase options for cost-effective constraint management, with a particular focus on measures that can reduce constraint costs in the short term, i.e. pre-2030.
- These measures do not address the underlying problem which are a lack of operational signals for efficient scheduling and coordination with system needs. Instead, they aim to resolve network constraints more efficiently than now.
- Constraint management projects currently underway include market-based solutions, technical upgrades, as well as transparency and data sharing measures.

Together, these three pillars create a framework for delivering a secure, efficient, and clean electricity market for GB.

1.3 RNP Balancing and Dispatch Vision

Balancing and dispatch arrangements must support a secure and cost-effective decarbonised system, facilitate efficient investment and provide enduring value for consumers.[1] These reforms will be developed and assessed considering the key factors outlined below.

1. **Maintain system reliability and operability** through market rules, processes, tools, and capabilities which must adapt to changing system conditions and prevent risks to system security[2]. This includes scaling essential operability services and developing new services to operate a clean power system securely and efficiently in constrained timescales to balance the system[3]. The market arrangements must evolve in this context by aligning with secure system operations, ensuring the system can respond to higher volatility and balance supply and demand.

2. **Operate the system at lowest cost for consumers**; this means ensuring the optimal use of all resources (supply, demand, and networks) across time, location, and markets. To do this, the market arrangements should facilitate efficient scheduling and dispatch decisions. This includes ensuring sufficient flexibility to adjust to changing system and market conditions through time, with competitive and transparent markets.

3. **Market arrangements should align with long-run signals for efficient investment decisions which align with system needs**. This must also be underpinned by sufficient certainty for investors to drive investment at pace, while enabling efficient entry and exit decisions.

4. **Market arrangements should be adaptive to change**, meaning both robust to future challenges and flexible to changes in requirements. This is key given the inherent uncertainty about future system and market conditions and events that cannot be fully anticipated; this includes economic, technological, political, and environmental factors.

1.4 Purpose of this Call for Input

1.4.1 What are we seeking input on?

This Call for Input focuses on the second pillar of the RNP package, the proposed balancing reforms that aim to ensure the system can be operated in a secure and efficient manner and deliver cost savings for consumers. We also introduce the case for further dispatch reform, which builds on the balancing reform and constraint management packages.

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[1] This has been developed in line with NESO's Market Design Framework, which is used to assess the efficiency of our balancing services markets.

[2] NESO's annual Operability Strategy Report (OSR) explores the operability challenges we expect to face as the electricity system decarbonises.

[3] NESO's annual Markets Roadmap sets the strategic direction for NESO markets in response to changing market conditions and evolving operability needs.

This Call for Input introduces the key principles and challenges that must be addressed by balancing and dispatch reform, and which have structured our thinking in assessing the impact of the reforms.

Our aim is to work collaboratively with stakeholders to ensure that the design and implementation of these changes reflect operational realities while delivering efficiencies that help keep consumer bills as low as possible and the system secure. This includes understanding the potential disruption of the reforms, including system upgrades and resource requirements. Your input will be essential to achieving these objectives.

We also invite stakeholders to share other potential reform options to address the balancing and dispatch reform challenges that have not been previously considered.

1.4.2 Balancing reform

The proposed balancing reforms have been identified with DESNZ and Ofgem to improve the operational efficiency of the system under a national wholesale market with self-dispatch arrangements.

Reform	Description
Lower mandatory BM participation threshold	This reform would lower the mandatory threshold for participation in the BM. It would increase NESO's visibility of and access to balancing resources which should lead to better coordination of resources to meet system needs, lower balancing costs through more efficient dispatch and increased competition, and increased system security.
Align market trading deadline and Gate Closure	This reform would realign the market trading deadline to BM Gate Closure, reversing BSC modification P342. Currently, the market trading deadline is at the start of the SP. Realigning this with Gate Closure aims to provide more certainty on the actions required post-Gate Closure, as wholesale market trading and NESO balancing actions are no longer occurring simultaneously.
FPNs to match traded position	This reform would require market participants to match their market traded position with their Final Physical Notification (FPN). This would prevent market participants from intentionally taking an imbalanced position at Gate Closure to benefit from exposure to the imbalance price, removing the risk that NESO takes actions based on FPNs that do not reflect the market traded position. In addition, ahead of Gate Closure, aggregated traded positions would be made visible to NESO to provide a better forecast of the upcoming market position, or where to expect that PNs might change as the market trades out an imbalanced position.
Unit-level bidding	This reform would require market participants to provide unit-level bids and offers in the day-ahead and intraday markets, instead of the portfolio-level participation that exists today, associating economic offers in these markets with specific units. This reform would support requiring FPNs to match traded positions, facilitate scheduling enhancements and increase transparency to better support Ofgem and NESO's investigation of behaviour that exploits inefficiencies in the market.
Shorter Settlement Period (SP)	This reform would reduce the SP length to 5 or 15 minutes, to provide better temporal price signals to market participants to resolve energy imbalances. Shortening the SP provides a more granular imbalance signal, incentivising more shape in market parties' trading to better match the demand curve and other behaviours, like fast ramping of interconnectors, BESS and demand-side flexibility.

We are seeking views on the effectiveness of the balancing reform package in addressing the stated challenges, potential impacts on reducing balancing costs, and market behaviour or distributional impacts across market participants. We are also seeking views on our proposed implementation pathway and associated challenges for industry.

It is important to note that the reforms are at different stages of policy development, and this will be recognised through the next steps and decision-making process for each reform. Unit bidding and a shorter SP are in an earlier stage of policy development and may require a further consultation following this Call for Input.

Cost-Benefit Analysis and Impact Assessment

After the Call for Input, the final proposed design options of the reforms will be subject to CBA and impact assessment to determine if it is appropriate to recommend them for implementation. We are seeking responses to inform this analysis and help ensure that the full impact of these reforms is appropriately captured.

Implementation Roadmap

Implementation assessments will be carried out to inform the CBA e.g. to identify the cost of IT system changes, revenue stream impacts, effects on investment cases, among others, and create an implementation roadmap. Your responses will be key in identifying the implementation impacts of the reforms and supporting the development of an implementation plan.

Decision-Making

The combination of detailed design, CBA/impact assessment and implementation assessment will be brought together to recommend a package of reforms for implementation. This Call for Input provides an opportunity for impacted parties to raise points for consideration within the decision-making process.

1.4.3 Dispatch reform

We also continue to explore a range of other dispatch reform options with DESNZ and Ofgem, with a view to improving system operability and reducing costs for consumers. Any reform to dispatch arrangements would look to build on the RNP package by exploring broader changes to the dispatch regime, aiming to better align market arrangements with system needs and improving the overall efficiency and operability of the system. Dispatch reform is at a less developed stage of policy development and the decision-making process than balancing reform.

We are seeking views on the case for further dispatch reform alongside the proposed RNP package including the range of dispatch reform options we should consider, and potential new ideas that we should consider.

1.4.4 Questions in this Call for Input

The questions look to explore the rationale, benefits, risks, and implementation considerations for each reform, as well as broader issues such as CBA, evaluation frameworks, and future dispatch arrangements. In this Call for Input, we have included both qualitative and quantitative questions. The qualitative questions are designed to capture detailed operational insights, evidence, and perspectives on the proposed reforms, including how they interact with system challenges, participant behaviour, and market functioning.

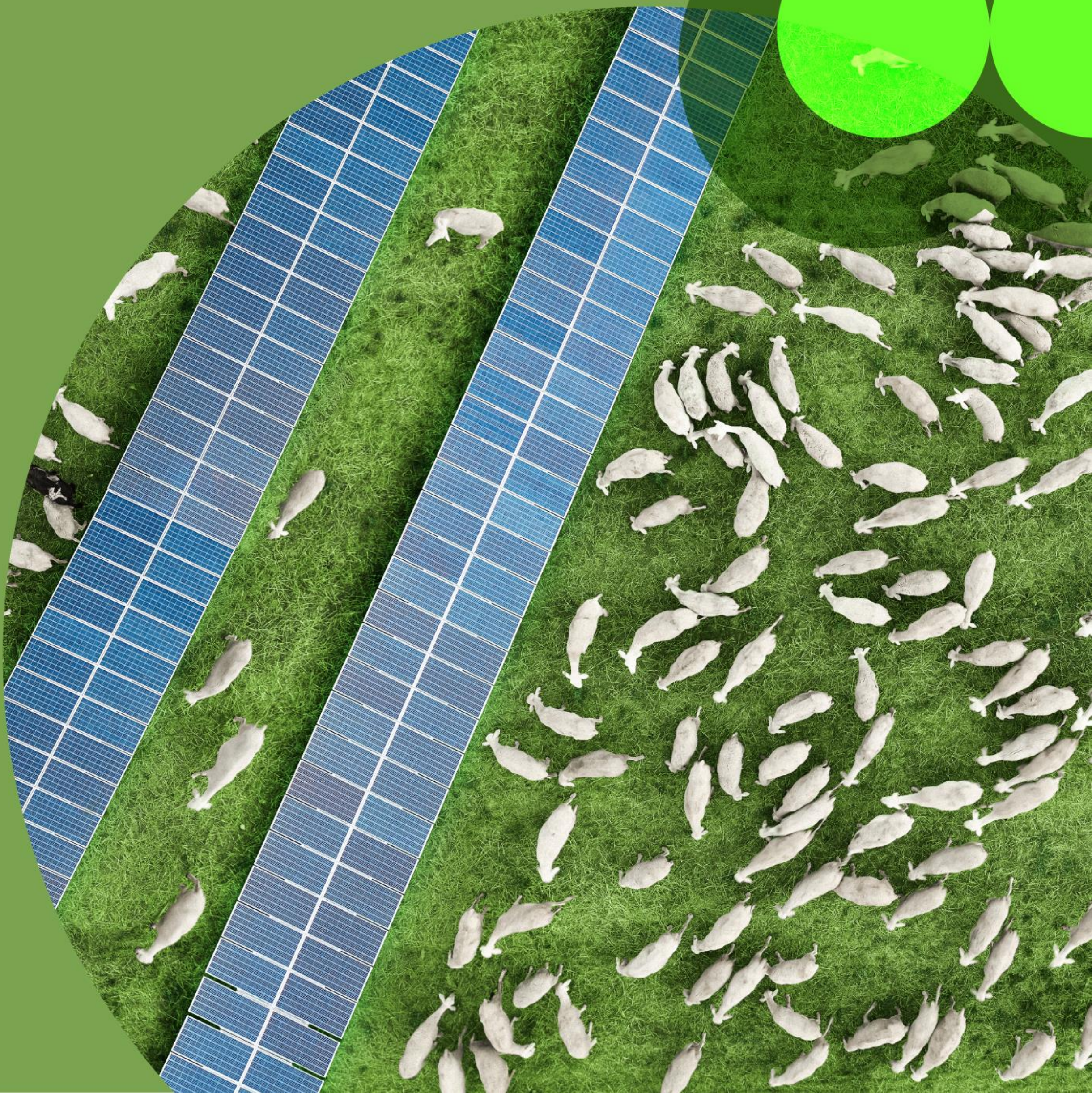
By contrast, the quantitative 1–5 scoring questions provide a structured way to assess stakeholder confidence in the core principles, perceived materiality of challenges, and the expected effectiveness, proportionality, and deliverability of individual reforms and the overall package. These quantitative inputs will support comparability across respondents and enable NESO, DESNZ and Ofgem to identify areas of convergence or divergence in stakeholder confidence levels, helping to prioritise areas for further analysis, design refinement, and engagement.

Your responses will be key to refining and adapting the design of the package, its sequencing, the implementation roadmap, and the impact assessment framework, ensuring the reforms deliver their stated objectives while keeping market impacts proportional.

The full list of questions can be found in Appendix 1.

See the Next Steps section for details on how to submit your response to the Call for Input.

2 Balancing and dispatch reform: challenges to address



2.1 The case for reform

2.1.1 Evolution of current arrangements

The current electricity market design was implemented in 2001 under the New Electricity Trading Arrangements (NETA), which moved England and Wales from a centralised pool to a bilateral trading model. The reasons for moving away from the pool included concerns about market power and high prices, lack of demand side participation, and governance arrangements that inhibited reform.[4]

The underlying philosophy of NETA was for balancing responsibility by market participants, with bilateral trading in the markets before Gate Closure and self-dispatch. Electricity would be treated as a commodity which could be traded on markets in different timeframes at a portfolio level, without any consideration for the physical limits of the power system, e.g. network constraints. Collectively, market participants are incentivised to balance overall supply and demand through their exposure to the imbalance price.

The physics of the system would then be taken into account by the System Operator (SO) after Gate Closure, to balance the system and maintain system security. The volume and cost of the actions required by the SO to balance the system determine the imbalance price. Here, the role of SO is to be the residual balancer.

A notable development occurred in 2005 when the British Electricity Trading and Transmission Arrangements (BETTA) extended the NETA arrangements to Scotland, granting all transmission generation in Scotland firm access to the newly formed GB market. With the introduction of Connect and Manage in 2010, generation projects could connect to the system ahead of wider transmission reinforcement works. This facilitated decarbonisation through faster connection of projects, particularly wind generation in Scotland. An important assumption which underpinned these decisions was that network congestion would remain low.[5]

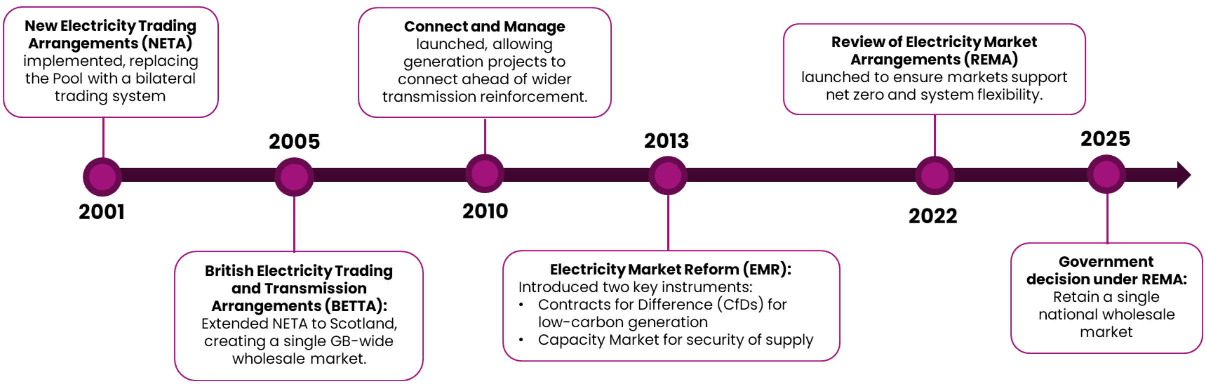


Figure 2: *Evolution of electricity market arrangements in GB*

Over time, these arrangements have evolved in several ways. This includes the shortening of Gate Closure from 3.5 hours to 1 hour, allowing market participants to adjust their positions closer to real-time, and the Electricity Balancing Significant Code Review, which

[4] Ofgem, 2001, The New Electricity Trading Arrangements
[5] Managing Constraints on the GB Transmission System

replaced dual imbalance pricing for imbalance settlement with single imbalance pricing[6], creating an incentive for market participants to system balance.

In 2013, the growth in renewables was accelerated with the introduction of Contracts for Difference (CfD) as part of Electricity Market Reform (which also introduced the Capacity Market), which provides long-term revenue support for low-carbon electricity generation. While these changes have successfully accelerated the deployment of low-carbon generation, the expansion has outpaced the delivery of network build, leading to a significant increase in the level of network congestion on the system. As a result, the assumptions made regarding future congestion when previous decisions were taken no longer seem to be valid.[7]

2.1.2 What has changed?

When NETA was introduced, almost all demand was met by a relatively small number of large thermal and pumped storage power stations connected to the transmission network, which were required to participate in the BM. The typical operating patterns of these units followed the demand profile, which itself was relatively predictable. These assets also inherently provided many technical characteristics required for the secure operation of the electricity system, such as reactive power and inertia.

Since then, changes in the type and location of generation on the system have led to a fundamental shift in the operating environment. The key trends identified and discussed below demonstrate this change and their impacts on the system.

A SYSTEM WITH INTERMITTENT GENERATION AND INCREASING NETWORK CONGESTION

With the accelerated pace of construction of renewable generation, electricity supply is increasingly met by weather-dependent generation. However, due to the availability of renewable resources, this generation is often connected at the periphery of the network. One consequence of this is increasing network congestion. The GB network now has multiple areas that are regularly congested, such as north-to-south power flows, export constraints in the east of England, and import constraints in the south of England. These constraints can be active independently, or together in different combinations and can be interdependent with each other[8]. As such, it is not just one constraint, such as the north-to-

[6] Under a dual imbalance price system, the imbalance price which market participants are exposed to depends on the length of the system *and* their imbalance direction. Market participants who are imbalanced in the opposite direction to the system length, i.e. they reduce the overall system imbalance, are paid or pay an estimation of the market price for that energy. Conversely, market participants imbalanced in the same direction to the system length, and so contribute to the overall system imbalance, are exposed to the costs incurred by the System Operator in balancing the system. In contrast, a single imbalance price system exposes market participants who are in the opposite direction to the system length to the same imbalance price as market participants in the same direction to the system length. Hence, a dual imbalance price does not 'reward' market participants for imbalance which reduces the overall system imbalance, and instead incentivises stronger self-balancing, whereas a single imbalance price incentivises market participants to reduce the overall system imbalance by taking an imbalance position in the opposite direction to the system length.

[7] In 2009, Ofgem raised concerns about the forecast significant increase in constraint costs to £262 million for 2009/10, and questioned the validity of the assumption made at the time of BETTA regarding the anticipated level of constraint costs.

[8] When taking an action to solve one constraint can make another constraint worse.

south export constraint, but multiple and interlocking constraints which creates a much more complex and costly problem to solve within balancing timeframes.

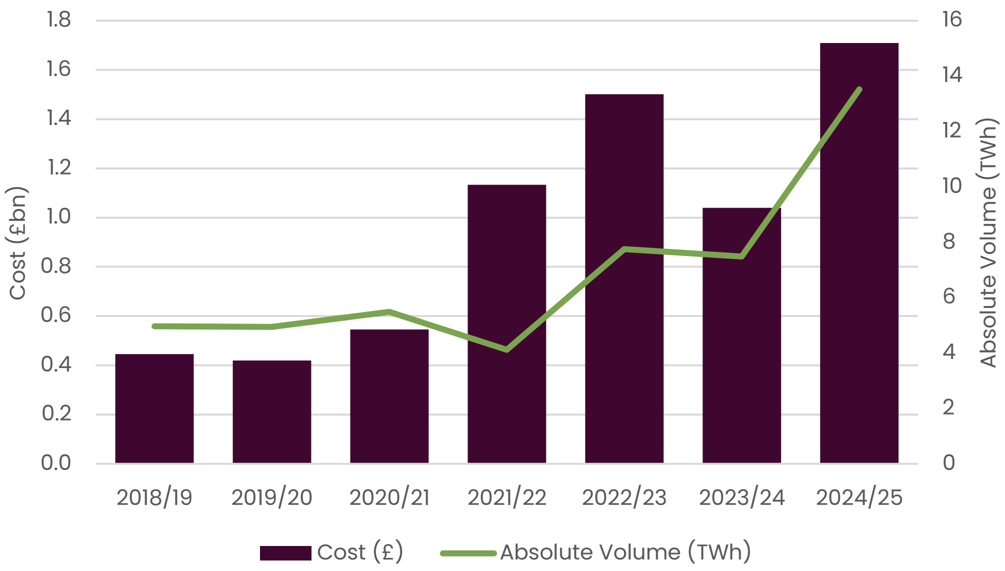


Figure 3: *Outturn thermal constraint costs and volumes, 2018/19 – 2024/25. Source: NESO 2025 Balancing Costs Report.*
Note: The increase in constraints from 2023/24 to 2024/25 is in part linked to planned outages in Scotland aimed at increasing the transfer capacity across key constraint boundaries.

Beyond congestion, due to the intermittency and generation profiles of renewables, these assets can leave gaps in the supply and demand balance that do not necessarily align with the operating patterns and physical restrictions of thermal units. For example, the lack of correlation between wind power output and the demand curve, coupled with market incentives to be scheduled at maximum potential, can create different operating patterns that change the nature of the actions NESO needs to take.

The emergence of fast-acting, flexible technologies

The system is also increasingly characterised by greater interconnection with other jurisdictions and the growth of fast-acting, flexible technologies, such as batteries and demand-side response, which now play an important role for balancing the system. For example, interconnectors allow GB to connect with European markets to benefit from differences in supply and demand patterns, providing additional system flexibility and sharing resources to where they provide most value. Electricity demand is also becoming an active participant in the market and can no longer be considered relatively predictable. However, this means the system is prone to much faster changes in generation and demand profiles, which often do not align properly.

While energy storage solutions like batteries do not have the same physical restrictions of thermal assets (e.g. ramp rates, Minimum Non-Zero Time, etc), their energy-limited nature introduces new intertemporal constraints, where the usable energy for SPs beyond Gate Closure cannot be known with certainty. Equally, NESO actions within-gate affect the energy available to trade in future periods. This inter-play of NESO balancing actions and wholesale market trading activities causes uncertainty for both NESO and market participants, limiting the efficient utilisation of energy-limited assets, as they cannot be scheduled in a co-ordinated way across multiple time-periods.[9]

The fast nature of these technologies, and being spread across many smaller assets, has changed how market participants must be coordinated for system security. Their flexibility means they can respond rapidly to price signals or changes within the SP, creating sudden swings in generation and/or demand. An example of how this challenge manifests is shown in Figure 4, whereby the scale of change in interconnector schedules close to real-time has increased significantly.

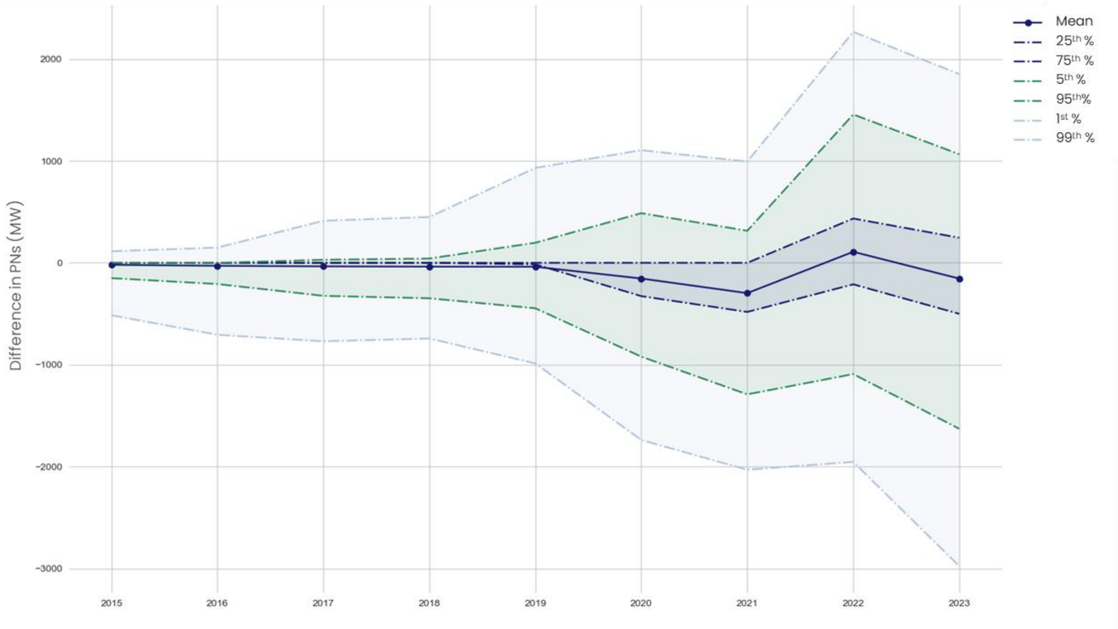


Figure 4: *Distribution of the difference between interconnector PNs 4 hours ahead and FPNs, 2015-23. Source: NESO analysis*

Furthermore, instead of one large unit which ramps slowly to reach its target position, there are multiple small units ramping quickly in an uncoordinated way, which risks frequency excursions and system constraints. This is particularly observed on the half-hour boundaries between SPs when market prices change, and large step-changes in generation and/or demand are becoming more frequent, necessitating expensive NESO intervention at the beginning and end of SPs.

THE GROWTH IN EMBEDDED GENERATION

A significant volume of capacity is now embedded (connected at the distribution network level), where most of these assets are non-Balancing Mechanism Units (BMUs), i.e. they do not provide visibility or cannot be accessed by NESO. We estimate that non-BMUs provided over 20% of total annual supply based on data from Digest of UK Energy Statistics (DUKES)[10] and NESO. However, at times of high solar and wind, non-BMU generation could be as high as 56% in 2025 and as much as 40% for 1 in 30 SPs, according to NESO analysis of DUKES.

[9] The implementation of GC0166 will introduce new dynamic parameters that facilitates more efficient use of energy-limited assets in the BM. While this should increase economic dispatch of energy-limited assets, more effective scheduling of these assets may still be limited as the energy available in future periods is uncertain.
[10] DUKES – Chapter 5

These numbers have been increasing over time and have sharply risen in 2025, as shown below.

Today, NESO has visibility of operational schedules through the submission of Physical Notifications (PNs) by BMUs. These are combined with demand and weather forecasts to understand the overall supply and demand balance, and identify what actions need to be taken to secure the system. However, as embedded generation has increased, a smaller proportion of total assets are submitting PNs, meaning aggregate PNs are not a full indication of the overall market position.

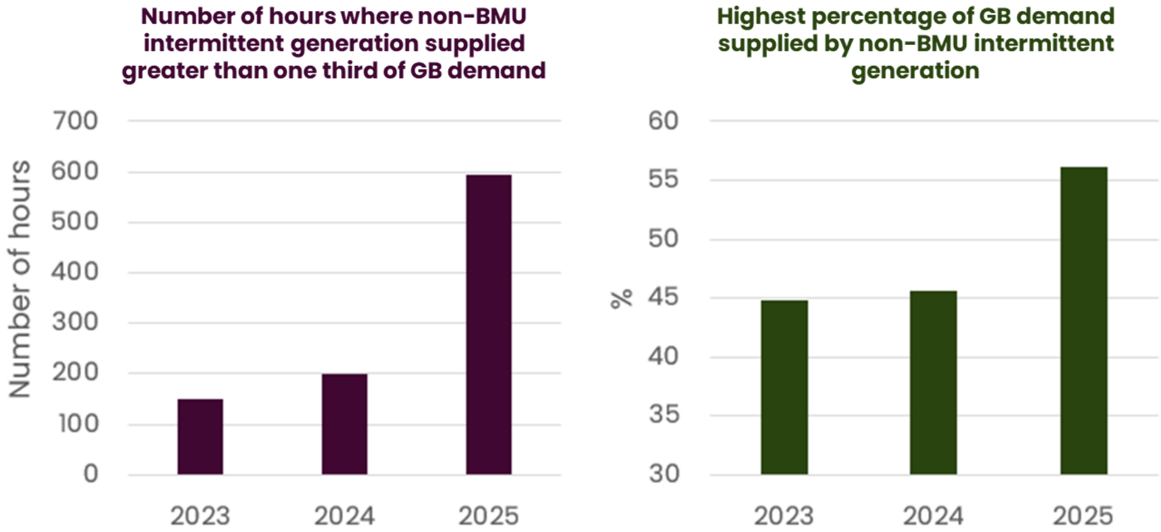


Figure 5: *Left: Increase in non-BMU intermittent generation, 2023-2025. Right: Highest percentage of non-BMU intermittent generation for one SP. Source: NESO analysis, DUKES.*

The growth of these assets presents an opportunity to unlock additional flexibility on the system, supporting the efficient and secure operation of a clean power system for the benefit of consumers. However, as these assets are not visible to, or accessible by NESO for balancing, we must undertake operational planning and redispatch with incomplete information of the market position and a more limited pool of resources. These assets are also responding in real-time to operational signals which do not reflect localised balancing requirements.

2.2 Principles for balancing and dispatch reform

EFFICIENT OPERATIONAL SIGNALS AND INCENTIVES FOR MARKET PARTICIPANTS

An overarching principle of a self-dispatch electricity market design is that the prevailing price signals in the wholesale market should incentivise market participants to resolve the majority of the energy volume and balance, with the SO managing the residual balancing needs left in real-time. The wholesale market can only deliver efficient outcomes if it has efficient operational signals and incentives, this concerns both the *locational* and *temporal* value of energy (i.e. “where” and “when”).

This is especially important in the future low-carbon system, where demand-side flexibility, other price-sensitive demand and energy storage of different durations are key to balancing the system with a high proportion of intermittent renewable generation.

Here, the energy imbalance price is a key driver of wholesale market trading, forming the reference price for market participants to trade against. The market design must therefore ensure that the energy imbalance price appropriately reflects the more volatile, responsive nature of supply and demand in the low-carbon, flexibility-led future.

A fair and efficient market requires market rules which provide sufficient protection against market power and gaming which seeks to take advantage of market arrangements at unnecessary cost to consumers.

As market and system conditions evolve, market rules must ensure that protections are fit for purpose to manage emerging risks, or address whether new or updated rules are required.

Improving market rules should provide benefits for all market participants, ensuring that market signals are transparent enabling better decision-making, and supporting effective competition on a level playing field.

This relates to how the wholesale market interacts with the technical constraints of the system, this includes how market participants trade in the wholesale market, and the corresponding transparency and enforcement opportunity this provides for market monitoring.

Clear handover of balancing responsibility between market participants and the System Operator

The market arrangements should be coherent across market timeframes to ensure alignment between bulk energy balancing ahead of time by the market, and the secure operation of the system by the SO in and close to real-time. This covers both market incentives which do not align with system needs, and timing overlaps that blur the interaction between the market and the SO.

This clear separation applies in both directions, for both sets of parties, and should address the inefficiencies in coordination between the wholesale market and balancing and remove competing control loops for frequency management.

This also includes what information is available to the SO and when, allowing for improved understanding of the expected balance of supply and demand. More certainty reduces instances of proactive actions (which coincide with the intraday market) for risk management that turn out to be unnecessary, which in turn facilitates the residual balancing role of the SO.

Secure and efficient operation of the system

Secure and efficient operation of the system requires sufficient visibility and access to resources available to be redispatched by the SO to balance the system. This includes the accuracy with which parties follow their submissions and instructions.

Resources should also be allocated efficiently across different timeframes, different locations, and multiple wholesale and balancing products and services. This relates to how effective the scheduling and dispatch design is at optimising costs and unit constraints over time, and in respect to the physical constraints of the network. This ensures that flexible assets are coordinated in line with system needs and provide consumer value.

The future arrangements must also consider the higher complexity of optimising across multiple and interdependent markets often with conflicting price signals, required to manage growing system operability challenges, to ensure resources are allocated to where they provide the most value. An efficient allocation of resources across all markets supports efficient price formation and reduces system and consumer costs. This includes ensuring that such markets are designed on a level playing field to maximise competition between all types of resources.

The design choices in this area should cover both production and consumption, so that the behaviour and flexibility of the demand-side and the generation-side are well understood and that both are able to participate effectively in balancing the system.

Questions on Reform Principles

Q1. Reform principles and inherent trade-offs:

Do the stated balancing and dispatch reform principles provide a coherent and achievable framework under a national pricing, self-dispatch market design?

Please consider:

- Whether the principles conflict (e.g. transparency vs liquidity, clear handover vs flexibility).
- Which principles should take priority, or where trade-offs arise. Please provide your prioritisation of principles.
- Whether any additional principles or changes to existing principles are required to ensure reforms support the future system needs.

Quantitative section

Q2. On a scale of 1–5, how confident are you that the balancing and dispatch reform principles set out in Section 2.2 (efficient operational signals, clear handover of balancing responsibility, secure and efficient operation of the system) are a suitable framework for reform under a national pricing, self-dispatch market design?

Scale:
1 = Not confident
5 = Very confident

2.3 Balancing and Dispatch: Challenges to address

Based on the market and system changes since NETA was introduced, our analysis of the future system, and what the other components of the RNP package are expected to deliver, we have identified four key challenges for balancing and dispatch reform to address.

Challenges to address
Operability and cost challenge from increasing redispatch
Insufficient visibility of and access to balancing resources
Misalignment and overlap between the wholesale market and balancing
Distorted wholesale price signals, and incentives to exacerbate system constraints

2.3.1 Operability and cost challenge from increasing redispatch

The volume of redispatch actions is expected to increase and remain at historically high levels, driven to a large extent by network congestion. As already shown, in the last six years alone, annual network congestion volumes have grown around 170%, from 5 TWh in 2018/19 to 13.5 TWh in 2024/25. To manage this, NESO redispatch actions at times account for over 50% of national demand, as shown by Figure 6. Looking forward, increasing redispatch will require even more significant intervention from NESO to unwind self-dispatch positions to balance the system and maintain system security.

This is because the networks and market arrangements in GB have not evolved sufficiently in line with the profound transformation in the electricity system towards decarbonisation. A rapidly changing generation mix, with significant volumes of new generation connecting to the periphery of the system outpacing network build is driving congestion up, and there is a fundamental misalignment between wholesale market signals and locational balancing needs, resulting in inefficient scheduling and dispatch.

Consequentially, the scale, complexity and cost of NESO's actions into the market to secure the system has grown, and will continue to grow, such that we are no longer the residual balancer as intended under the current market arrangements. Instead, NESO often resembles a de facto central scheduler, undertaking significant volumes of redispatch to align the wholesale market position to the needs of the system. This is contrary to its intended role and undertaken without the corresponding tools and framework. This intervention into the functioning of the wholesale market can impact market incentives and reduce transparency for operational and investment decisions.

As a result, annual balancing costs totalled £2.7bn in 2024/25 and are projected to reach approximately £4-8bn in 2030[11], with the size, timing and duration of the peak in balancing costs dependent on the delivery of network build (and in the absence of market reform).

[11] NESO 2025 Annual Balancing Costs Report. Updated figures will be available in the 2026 Balancing Costs Report.

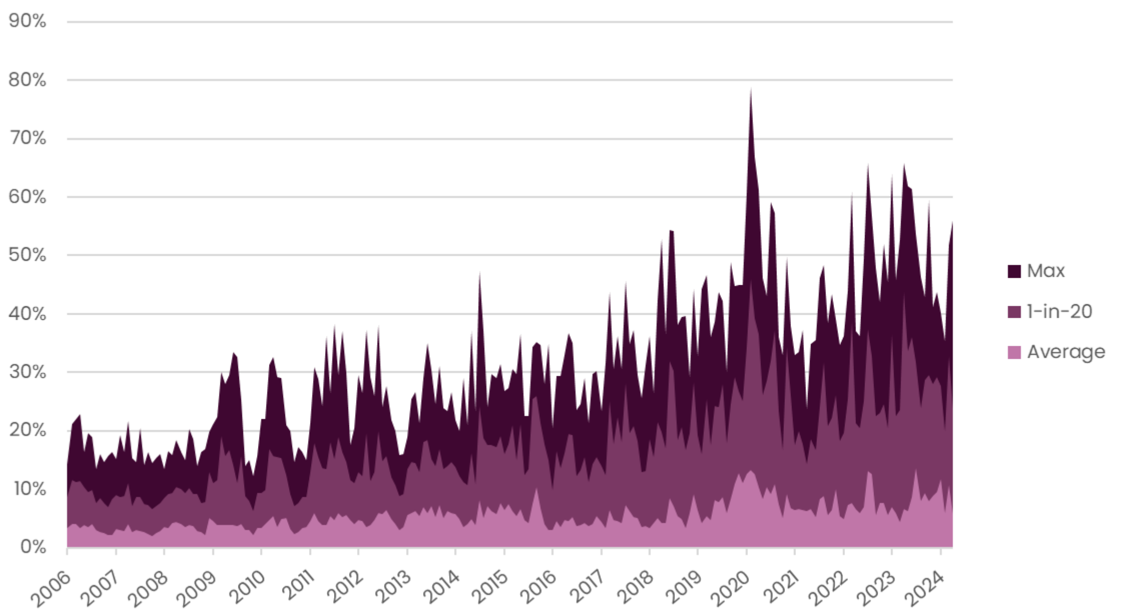


Figure 6: *Historic redispatch volumes as a share of national demand. Source: NESO*

NESO has previously shown that the peak in balancing costs in 2030 could be reduced if three critical network projects, which have delivery dates after 2030, are accelerated. At the same time, any delays to delivery dates for new network build could cause balancing costs to peak higher than projected and/or be sustained into the early 2030s.

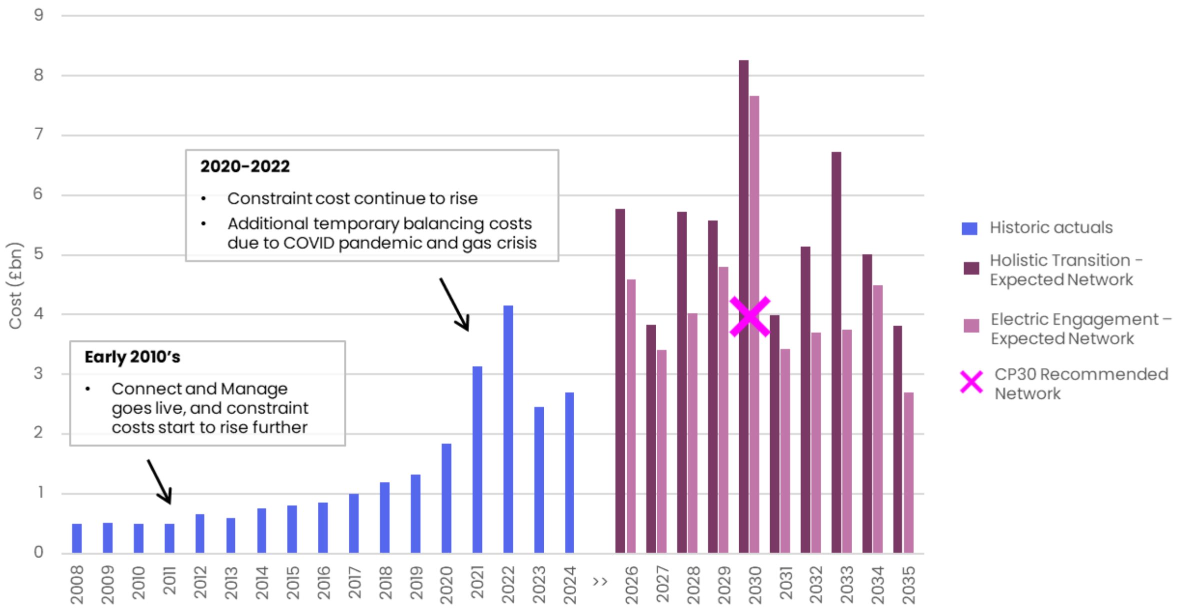


Figure 7: *Balancing cost history and projections. Source: NESO*
Note: The pink cross shows the impact of the recommended network on balancing costs in 2030. After 2030, the expected and recommended networks are identical. The projections are a best view of trends in future balancing costs based on historical cost components and potential future scenarios. There are wider factors that can drive increases in balancing costs that must also be considered, notably wholesale energy prices which have knock-on effects on balancing costs.

NESO's ability to meet increasing operability challenges depends on how closely the wholesale market position is aligned to the needs and capability of the system, and to what extent tools and resources are available to realign the two. The further the market is from an operable position, the greater the redispatch required. With greater redispatch required, it is more complex to find viable solutions across multiple interacting system needs in short timescales.

NESO has made significant progress in recent years to manage increasing system complexity through enhanced capabilities to send instructions to many smaller, flexible assets and opening new market routes for flexibility providers. The volume of instructions that NESO now sends to keep the system in balance has grown ten-fold in 18 months (from ~20,000 in December 2023 to over 200,000 in June 2025).

However, the projected increase in redispatch requirements poses several operability challenges and inefficiencies, which are discussed below.

Growth of Interconnector redispatch

Looking ahead, Clean Power 2030 (CP30) modelling by NESO projects that, without any reform, redispatch volumes could be up to 50% higher in 2030 compared to 2024, and interconnector redispatch volumes could be 500% higher than today, even with the recommended network build outlined in the CP30 report. Interconnector modelling is sensitive to assumptions and price forecasts from neighbouring countries; however, these figures illustrate the potential scale of future interconnector redispatch.[12]

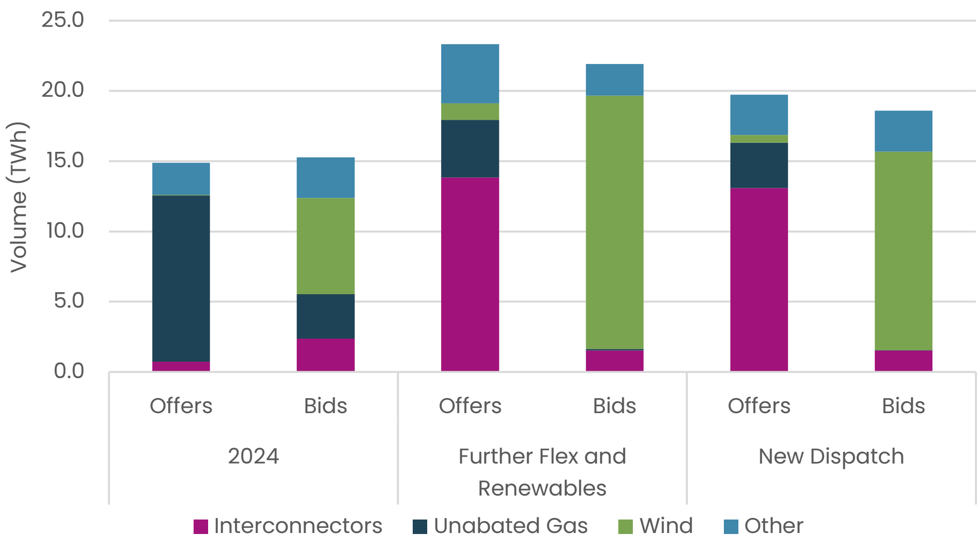


Figure 8: *Historic and projected interconnector redispatch volumes. Projected volumes taken from Clean Power 2030 modelling. Source: NESO*

If NESO were unable to redispatch the required volume on interconnectors[13] to manage system constraints (e.g. due to system conditions in the connected market), then we may need to rely on unabated gas generation at high cost to manage these volumes, assuming units are available, which would undermine the ability to run a Clean Power system.

[12] NESO Clean Power 2030 – Annex 2

[13] Interconnector redispatch is currently undertaken through countertrading and System Operator (SO-SO) trading, which is reliant on the cooperation of the connected System Operators

LOCATIONAL OPTIMISATION OF FLEXIBLE ASSETS

The single national wholesale price can provide the "wrong" signal for when flexible assets in different locations should generate or consume energy. This means the scheduling of flexible assets (storage, interconnectors and increasingly the demand-side) is uncoordinated in relation to network constraints, both helping and hindering constraints in unpredictable ways.

Analysis by FTI Consulting[14] shows that for the period April to September 2024 for four batteries located in the north of GB, 59% of the volume of their activations in the BM were done to nullify the schedules of those same units. In other words, this means the majority of actions were to prevent the units from exacerbating congestion, rather than using them to alleviate congestion. This dynamic means increasing flexibility in some locations on the GB network could currently increase, rather than decrease, the cost of congestion which falls on consumers.

Additionally, when storage assets are redispatched by NESO, it can create knock-on impacts as the units then have a different energy position than they expected. This then impacts on the availability or unavailability of energy in the market in future hours. This means that when constraints are active for multiple periods, the energy volume constrained off in storage units can perpetuate, leading to additional future constraint actions to buy out the same volume again in future periods; this dynamic is known as "repetitive re-trading".

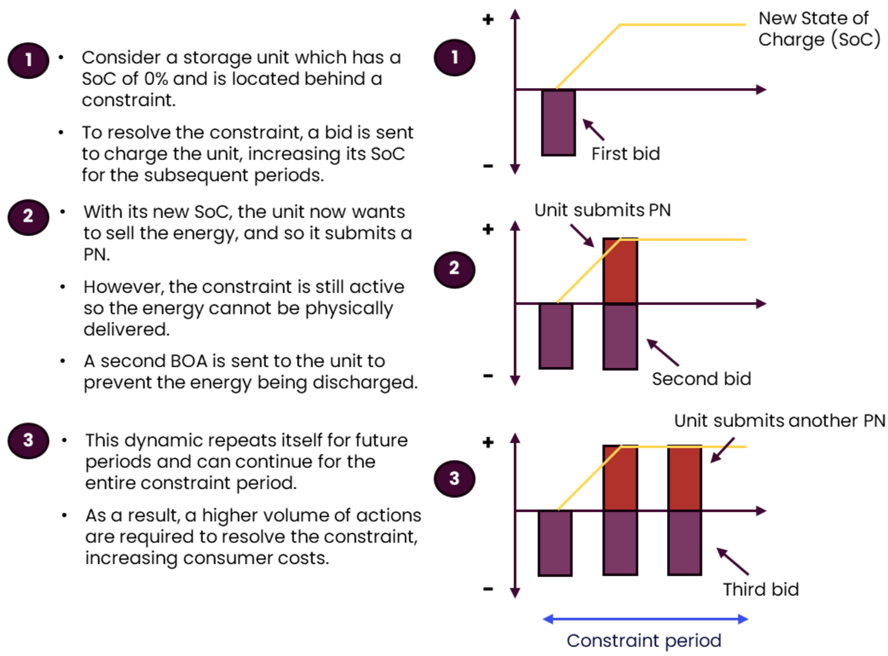


Figure 9: *Illustrative example of inefficient management of storage units*

Therefore, assets continue to generate revenue from the wholesale market on the stored energy, while contributing to the balancing costs associated with constraint management.

[14] How the current GB wholesale market design fails to make best use of flexible assets – FTI Consulting

NESO has conducted an analysis of additional PNs submitted after a system-flag bid was received by units behind active export transmission constraints. This utilised internal and external data and included the provision of ancillary service contracts and their impact on market behaviour behind constraints. The additional PN volume would require balancing actions to bid down the additional PN and replace the energy outside the constraint to maintain system security.

The initial assessment included not only storage assets, but also other fuel types present behind export constraints, including Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT), non-pumped storage hydro, and small BMU providers (e.g., aggregators with battery storage).

The analysis calculated that the total consumer cost of this behaviour behind constraints was £136.3m (using a 12-hour search period) for the period November 2024 to October 2025, which included £59.5m of wholesale costs to the consumer and £76.8m of balancing costs to replace the curtailed energy. The analysis found that most actions (81.7% of total balancing costs) were caused by storage units: battery and pumped storage behind constraints. The majority of the balancing costs, however, were from replacement energy actions to increase generation on a unit outside constraints using offers in the BM.

Box 1: Modelled redispatch on a high wind day in the 2030s (1-hour period)

The challenge of coordinating schedules in relation to network constraints is increasing. NESO modelling shows that under conditions of high wind in Scotland and the North Sea, the self-dispatch position would flow significantly more power from north-to-south than the physical capabilities of the network, with interconnector flows mostly exporting from GB to the connected jurisdictions, exacerbating network constraints.

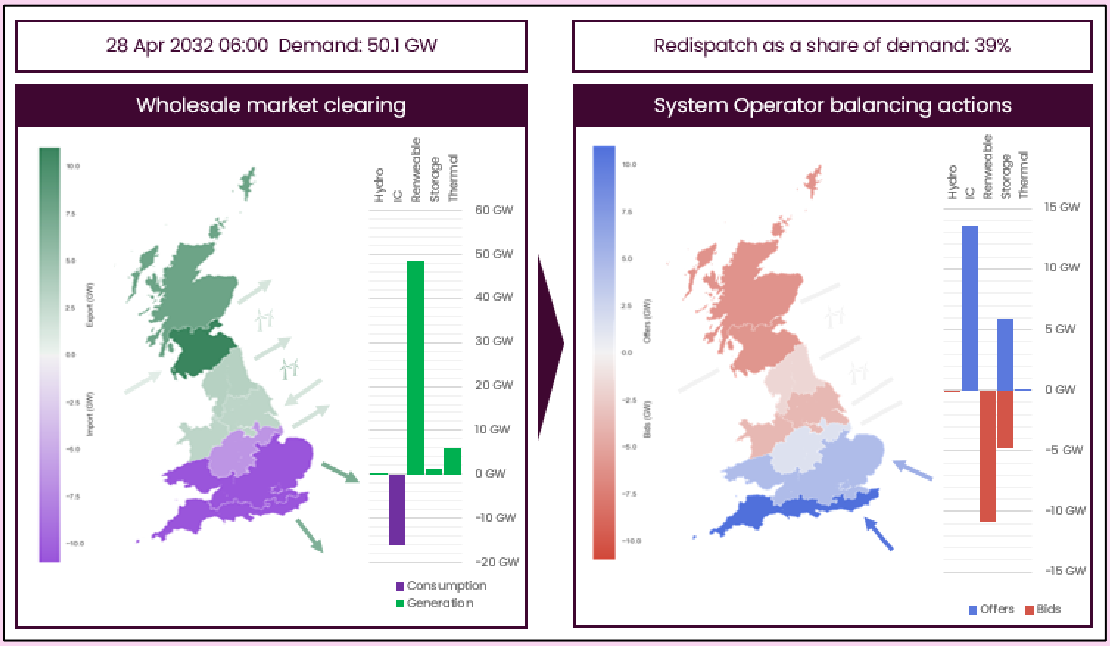


Figure 10: *Modelled wholesale market clearing and redispatch, 28 April 2032. Source: NESO*
Note: Wholesale market clearing shows the market position for the import or export of power for different regions in GB under a national price, and the net flows on the interconnectors to or from these regions. System Operator balancing actions shows the volume of bids and offers NESO needs to take in each region to resolve network constraints that arise from the market dispatch position.

In these conditions, significant NESO intervention is required to constrain approximately 11 GW of wind generation, particularly in Scotland, to secure the network and take the equivalent of around 14 GW of offers on the interconnectors in the south of GB to resolve the resulting energy imbalance (i.e. replacement actions) and balance the system. Storage assets are similarly not scheduled in line with network constraints, requiring predominantly bids for assets located in the north of GB and offers for assets in the south, totalling 10 GW of actions. In this period, NESO redispatch actions as a share of demand is 39%.

This example illustrates the potential scale of the future operability challenge, with GB reliant on interconnector availability as an important source of flexible capacity for redispatch, with storage assets providing additional flexibility to resolve system needs.

Allocation of resources across products and services

As redispatch volumes grow, NESO would increasingly rely on a complex suite of ancillary services and BM actions to unwind wholesale market positions. Such arrangements would be complex and costly to operate and trade in, in turn having a direct impact on market participants' revenue opportunities and consumer costs.

The increased need for numerous and interdependent ancillary services markets (and the growth of other bespoke flexibility markets), increases the scale and impact of opportunity cost forecast errors. By procuring energy and ancillary services independently (and sequentially), market participants need to make an upfront choice as to which market to participate in (i.e. they must consider the opportunity cost of foregone revenues in other markets). This is shown illustratively below.

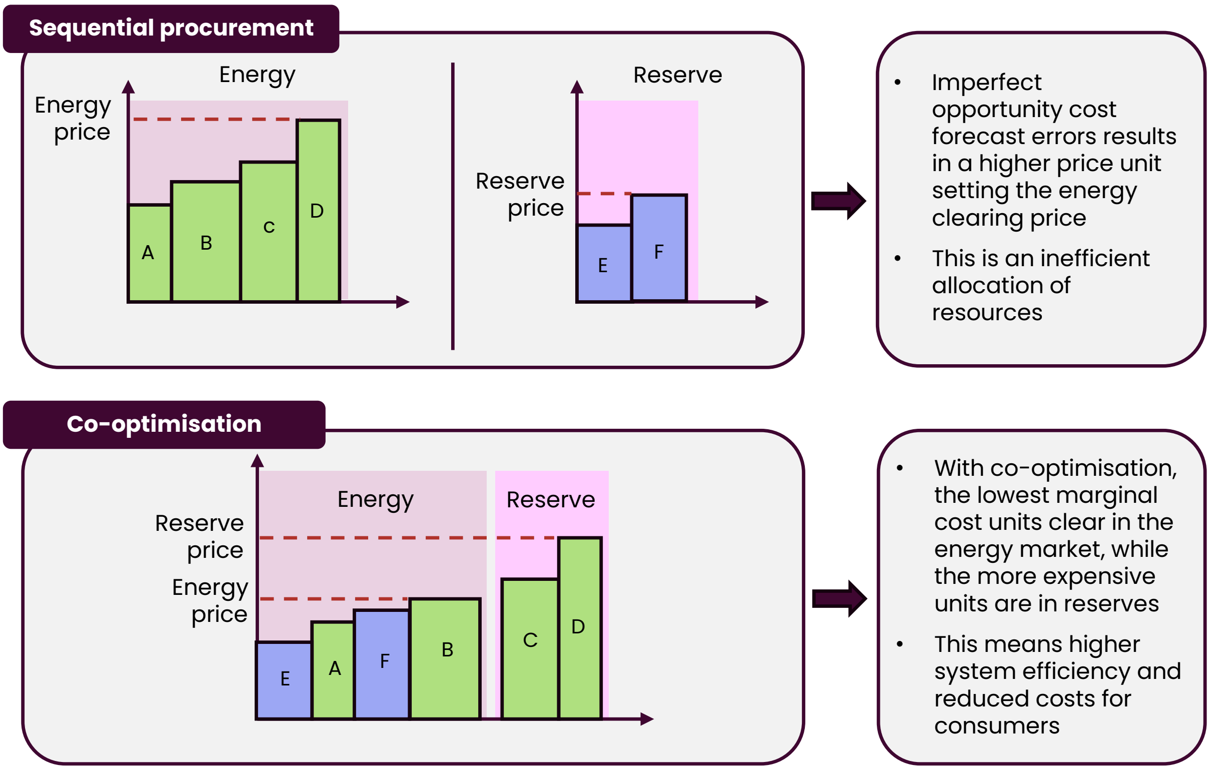


Figure 11: *Illustrative example of sequential vs co-optimised markets for energy and ancillary services*

This is despite the interdependencies between such markets. Opportunity cost forecast errors result in a reduction of allocative efficiency (if resources are not allocated to where they provide the most value), which distorts price signals and increases consumer and system costs. If more markets are created to offset the ineffectiveness of self-balancing, there could be a loss of competition, and higher costs, as resources are spread more thinly across different markets.

2.3.2 Insufficient visibility of and access to balancing resources

PNs and other BM parameters are fundamental to being able to plan and operate the system securely and efficiently. If NESO does not have visibility of what units are planning to do, this increases operational risk, and it is likely that inefficient actions would take place resulting in higher balancing costs. Limited access to flexible assets further reduces NESO's ability to resolve increasing operational issues from the market's self-dispatch position and removes opportunities for balancing resources to be efficiently utilised.

Since 2011, the share of assets connected to the distribution network has grown from 15% of total generation capacity in GB to 36% in 2024, of which most are not in the BM. Approximately 33 GW (or >75%) of distributed energy assets[15] are not visible to NESO or accessible for balancing in real-time, creating operational challenges.

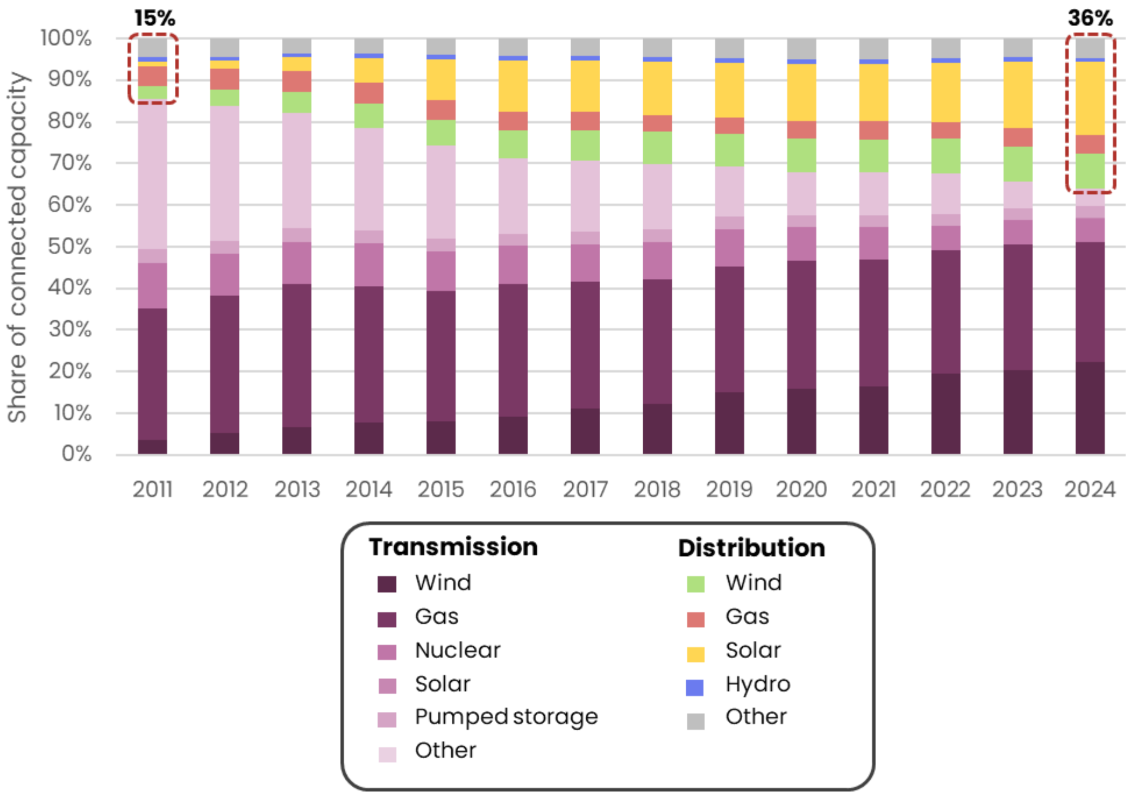


Figure 12: *Historical share of generation capacity by connection level. Source: DUKES*

This means taking unnecessary and inefficient BM actions due to incomplete information, greater proactive actions by NESO to manage higher levels of uncertainty over market

[15] This includes both DERs and CERs

outcomes, and increased use of frequency response services to manage unexpected and short notice changes in demand.

Box 2: Impact of non-BMU generation on operational planning

We often observe changes to interconnector schedules with no corresponding changes to other PNs, causing uncertainty over the market position and the actions we need to take.

For example, on 17 September 2025 between 18:00 and 19:00, NESO observed a change of 2,200 MW to interconnector schedules that was traded by the market, decreasing expected imports from Europe to GB. As a result, NESO added an additional 1,450 MW of small BMUs to the operational plan to account for the loss of imports. However, much of this additional generation was not eventually required as the anticipated shortfall was made up by non-BMU generation.

We did not know if the interconnector flow changes would be offset by changes in non-BMU generation (observed as a change in the transmission system demand), or whether the market had traded an unbalanced position requiring NESO actions. Without visibility of non-BMUs or of the overall market traded position, NESO cannot reasonably anticipate or rely on non-BMU generation to meet expected shortfalls, and therefore proactive action and/or procuring more response and reserve is more likely to be required for risk management, at additional cost to consumers.

The operational planning for the system is based on the FPNs notified to NESO by market participants at Gate Closure, and other additional system information. With this, NESO may expect the system to be overall short or long, and instruct corresponding BM actions. However, non-BMUs (which are not visible to NESO) can also foresee the length of the system and deliberately change their physical output relative to their traded position to take advantage of the expected market length.[16]

The actions by NESO and by market participants are therefore poorly coordinated and can result in inefficient additional BM actions by NESO to overcome not only the initial energy imbalance, but also additional actions by other market parties.

Looking forward, to provide the distributed flexibility needed for a clean power system by 2030, the capacity of distributed energy assets could grow to 65 GW. With a lower proportion of assets available to NESO for balancing, there is reduced flexible capacity in real-time to resolve system issues and balance supply and demand. This means less competition and liquidity in the BM – and therefore higher prices - and less efficient dispatch of balancing resources. In addition, non-BMU assets could be responding to wholesale market signals in real-time, which can often counteract or compete with balancing requirements, resulting in higher operational risk, poor coordination between wholesale and balancing markets, and potentially creating additional actions at further consumer cost.

This is particularly challenging in a highly congested system with high redispatch requirements which are often complex to resolve, necessitating a high volume of actions

[16] This is an example of Net Imbalance Volume (NIV) chasing.

across the system. Hence, increasing the share of generation in the BM allows for more coordinated and efficient dispatch solutions for balancing, utilising available resources to meet system needs at lowest cost for consumers.

In summary, ensuring sufficient visibility *and* access is vital to secure and efficient balancing, supporting better forecasting, and enhanced network contingency planning and system operation.

2.3.3 Overlap between the wholesale market and balancing

Currently, the roles of market participants and NESO in balancing the system in real-time are somewhat blurred by conflicting rules and signals.

For energy balancing, there is an overlap in the period between Gate Closure and real-time during which actions to energy balance the system are simultaneously taken by NESO and by market participants (mostly, but not only, non-BMUs). For system actions, particularly network constraints, the overlap between actions taken after Gate Closure and in real-time creates additional challenges, as NESO must also carry out redispatch to resolve network congestion, not just energy imbalances. Once again, simultaneous actions by NESO, and the participants due to the current market arrangements, can create situations where the actions directly conflict, forcing NESO to take additional balancing actions at additional cost to the consumer.

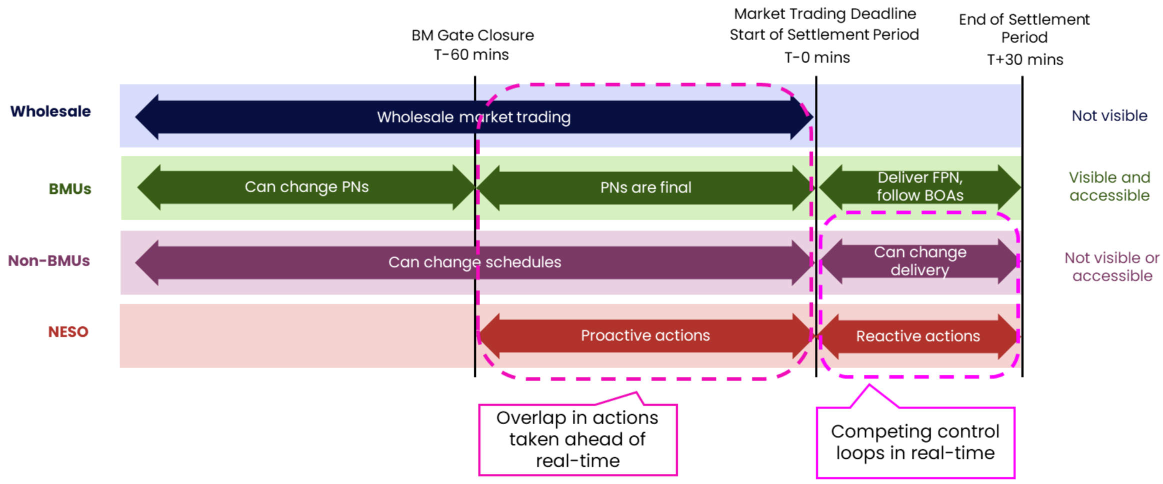


Figure 13: *Misalignment of GB rules and incentives*

This challenge can be broken down into the following sub-challenges:

STEP CHANGES ON SETTLEMENT PERIOD BOUNDARIES

Large step changes and the mismatch between unit ramping and the demand curve suggest that the current SP lacks sufficient granularity to incentivise wholesale market participants to trade in a way that maintains the system's energy balance.

As more flexible assets, price-responsive demand, and algorithmic trading spread across hundreds or thousands of assets, the risk of simultaneous, uncoordinated ramping in response to price signals increases. To manage this risk, NESO must use short-duration, high-priced balancing actions and increased use of response and reserve services to simply counteract market behaviour that is responding to price signals, adding costs to consumers.

As a mitigation to these events, NESO has had to increase its dynamic response holding to manage the frequency, due to the uncertainty of how demand and embedded generation will behave in response to wholesale and balancing signals. Focusing on pre-fault frequency services Dynamic Moderation (DM) and Dynamic Regulation (DR), spending has been increasing to improve pre-fault frequency quality, rising around 3-fold to £8.87m per month from the start of 2025 to October 2025, as shown in Figure 16.

Box 3: Impact of step-changes on frequency management

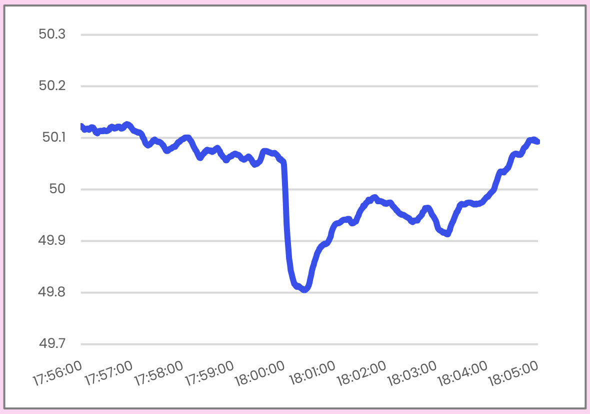


Figure 14: *System Frequency, 11 December 2024. Source: NESO*

On 11 December 2024 an unexpected step-change increase in demand of 250 MW was observed at the start of the SP for 18:00, and in total demand increased by 350 MW in less than 1 minute. At the time, system demand was ~37.4 GW, and frequency decreased by 0.24 Hz from 50.04 Hz to 49.80 Hz.

Post-event analysis found that this change was driven by a relatively small number of Grid Supply Points (GSPs) which contain embedded batteries, which we infer were responding to wholesale price signals, however, this is not certain and other factors could be driving this behaviour. The frequency and potential size of this risk have increased and is expected to grow as more flexible capacity connects to the system, emphasising the importance of aligning operational signals for flexibility with system needs.

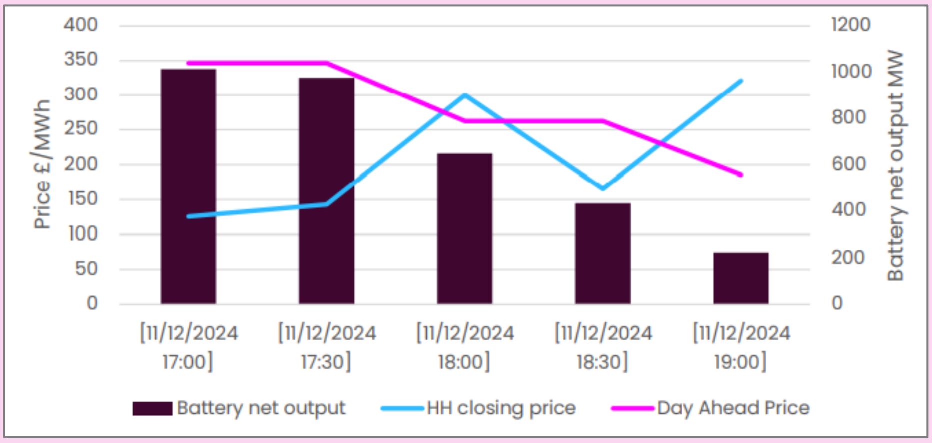


Figure 15: *Battery output and wholesale market prices, 11 December 2024. Source: NESO*

The above chart shows the metered battery output for BM-registered batteries, against the wholesale day-ahead (pink line) and intraday (blue line) prices. The market signals are somewhat unclear to understand the observed increase in demand. The day-ahead price dropped by almost £100/MWh between the periods 17:30-18:00 and 18:00-18:30 which could explain the increase in demand, however, the intraday price was high for

18:00-18:30 compared to the surrounding periods which may have incentivised battery output to remain higher than otherwise.

Looking forward, we expect response and reserve costs to be driven by a changing generation mix which is more volatile, leading to more significant energy swings and frequency variations which are faster and harder to predict.[17]

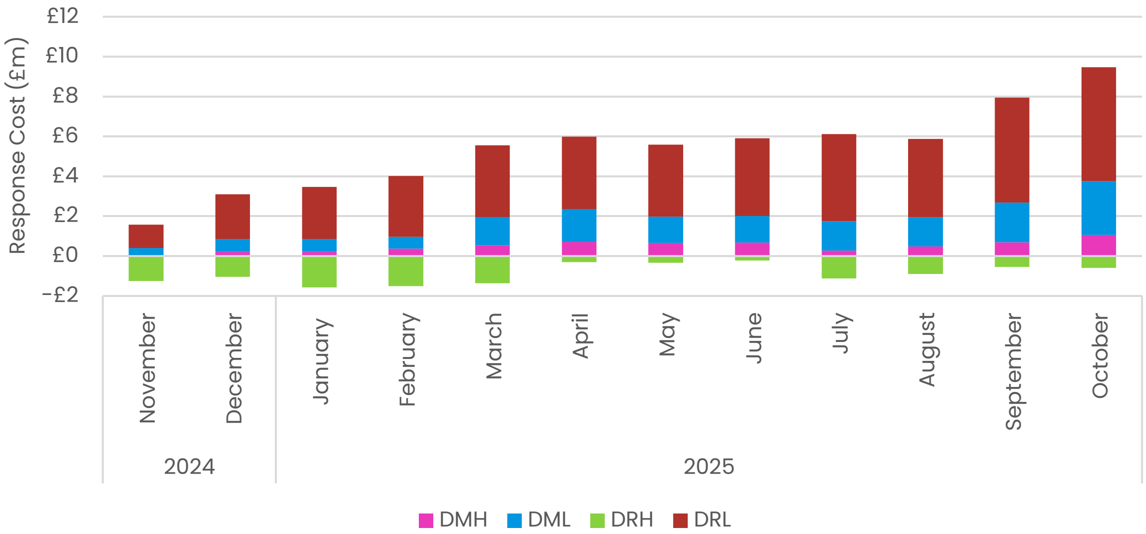


Figure 16: *Pre-fault frequency services spend, November 2024 - October 2025. Source: NESO*
Note: DM: Dynamic Moderation; DR: Dynamic Regulation. Each service has a High (H) and Low (L) direction.

ENERGY BALANCING POST-GATE CLOSURE

Under the current arrangements, market participants are able (and arguably encouraged) to self-balance between Gate Closure and the start of the SP, notably through trades with non-BMUs. For example, in order to avoid paying an imbalance price (in case their physical output deviates from their traded position due to a change in weather forecasts), intermittent generation across the network could trade post-Gate Closure to manage their imbalance exposure.

This form of energy balancing can be beneficial during periods of low or no network constraints by reducing the volume of balancing actions NESO needs to take in real-time. However, it can also pose operational challenges to NESO if the physical location of the units actually delivering the output (non-BMUs) does not align with network constraints. In particular, since NESO only has visibility over the FPNs rather than the traded position, NESO may act on the information contained in the FPNs, for example, seeking to balance the expected wind output in location A. However, the owner of the wind unit may have undertaken a trade with a non-BMU party such that the ultimate physical output comes from a different unit in location B.

This type of decentralised balancing of unintentional imbalances (via the intraday market or internal trades) can therefore conflict with the physical needs of the network. In turn, it

[17] NESO Balancing Costs report 2025

may lead to balancing actions, related to network constraints, taken by NESO that are not efficient (or could even be counterproductive).

Box 4: Impact of energy balancing by the market post-Gate Closure under a congested network

In the example below, between Gate Closure and the start of the SP a wind generator located in the North forecasts an increase of 5 MWh (10 MW) in available wind production for the upcoming SP.

Suppose that in this period, there are no transmission constraints, if the wind generator deviates from its FPN and generates the additional 5 MWh, which would be paid at the imbalance price, the overall GB-wide Net Imbalance Volume (NIV) is 10 MW long across the SP. This would lead to an increase in the volume of balancing actions required to balance the system. The wind generator can alternatively self-balance by selling the additional volume in the intraday market to a battery located in the South. This trade eliminates the GB-wide NIV and therefore reduces the need for BM balancing actions.

Suppose now that there is a North -South transmission constraint. With no trading there is a 10 MW imbalance in the North for NESO to resolve. However, if the wind farm owner undertakes the same self-balancing trade as described above intra-GB congestion is exacerbated, which in turn leads to an increase in the required volume of constrained-on actions in the South and the North.

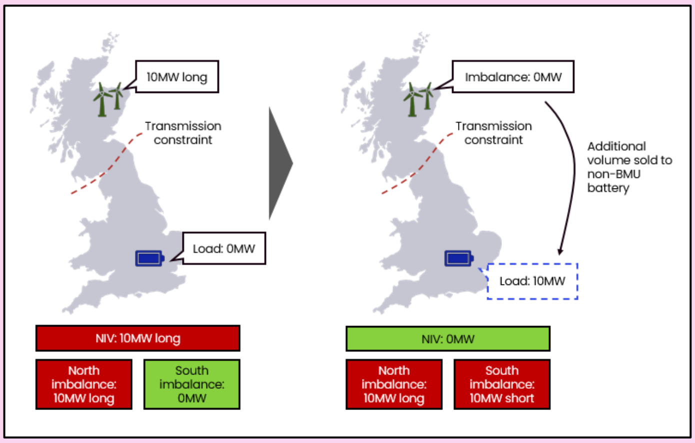


Figure 17: *Example of post-Gate Closure energy balancing increasing network constraints*

In the figure, on the left-hand side, NESO only needs to constrain the wind generator to resolve the energy imbalance. However, on the right-hand side, as the self-balancing trade cannot be physically delivered, NESO needs to constrain both the wind generator *and* the battery (We assume that in this period, the windfarm opts not to curtail the additional wind generation).

Absent the trade, the wind generator may have opted to curtail the unanticipated production itself to avoid the imbalance charge, which would reduce the volume of constrained-off actions in the North. Alternatively, the wind producer may have opted not to curtail the additional wind – this would have led an increase in constrained-off actions in the North (either of this windfarm or another BMU in the North that had bids available) but not in the South. In the latter case, the imbalance volume would be half of the imbalance volume under the intraday trade.

STRATEGIC POSITIONING AHEAD OF REAL-TIME

At Gate Closure, BMUs can opt to have an open position – which we define as the sum of their FPNs not matching the traded position at an aggregate portfolio level. These open positions can be later closed or left open depending on trades being conducted between Gate Closure and real-time and the evolution of the anticipated system energy imbalance. This is shown illustratively below.

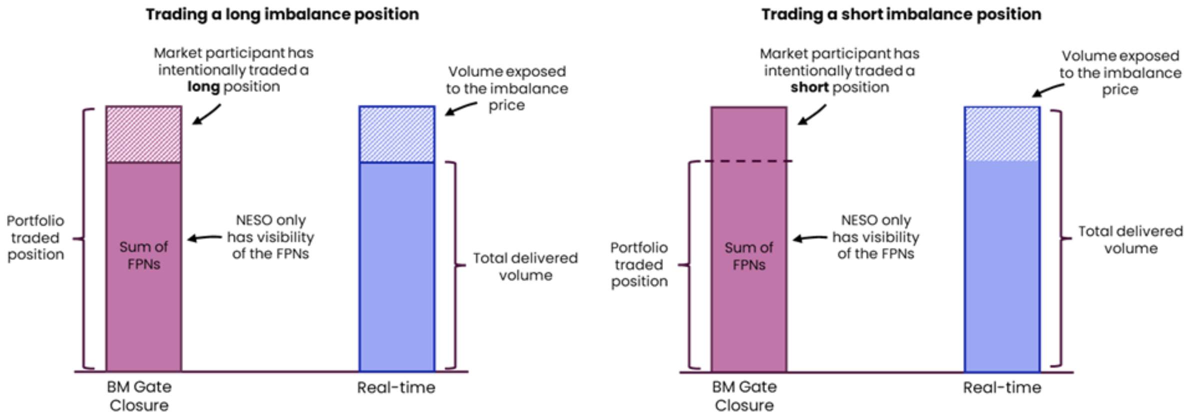


Figure 18: *Illustrative example of strategic imbalance positioning*

Hence, from the information provided through the FPNs, NESO does not have a clear visibility of the market length at Gate Closure, i.e. the expected balance of supply and demand at GB-wide level. This means that NESO could be taking energy balancing actions based on the FPN information, but in fact these actions would turn out to be incorrect (and inefficient) with respect to the traded position of market participants. As a result, NESO could be taking unnecessary, inefficient or even counterproductive balancing actions.

NET IMBALANCE VOLUME (NIV) CHASING IN REAL-TIME

NIV chasing is when market participants deliberately expose themselves to imbalance (i.e. their traded position is different from their metered output) to benefit from the imbalance price. The single imbalance price incentivises market participants to take a position which is *opposite* to the overall system length, receiving a relatively high price for going long in a short system, or paying a relatively low price for going short in a long system. We define NIV chasing in real-time as 'reactive' NIV chasing, whereby NIV chasers change their physical output in real-time based on NESO balancing actions and system conditions.

Non-BMUs have a greater ability to NIV-chase compared to BMUs since they are not required to submit FPNs and hence are not bound by the Grid Code obligations with respect to those FPNs. As such, they can change their physical output in real-time and have access to the best information about the expected imbalance volume in a SP (and hence the likelihood of a commercially profitable NIV chasing action is highest).

Box 5: Frequency oscillations from NIV chasing

On 8 November 2025, significant movements in demand started at 20:30 and continued periodically until the end of the SP at 21:00, creating large system frequency oscillations. Each major swing in system frequency lasted for around 1 minute. These movements are inferred to be as a result of NIV chasing by non-BMUs, based on the information available to us. The step changes in the frequency were significantly suppressed by frequency response services, DM and DR. Due to the volume of DM and DR on the system at the time, the large oscillations observed are highly unusual.

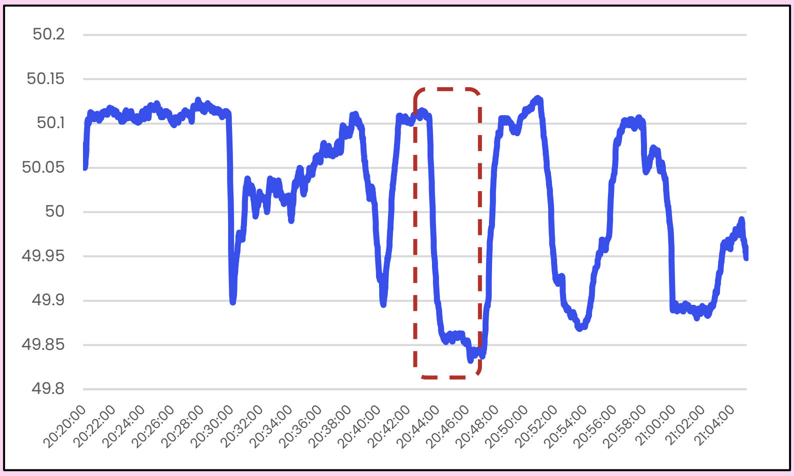


Figure 19: *System Frequency, 8 November 2025. Source: NESO*

Post-event analysis shows that the final NIV across the SP was long by 13.4 MW but hovered above and below 0 MW throughout the SP, likely as NIV chasers oscillated between long and short positions.

During this period, multiple BM actions were sent to batteries in both directions where each instruction would have sent new signals to NIV chasers as the evolving NIV changes from short to long and back again. This could then induce more NIV chasing, resulting in the oscillating frequency behaviour observed.

Focusing on the frequency drop at around 20:43 (shown in the red highlighted area), we estimate that the volume of NIV chasing was up to approximately 2 GW, from sources which are not visible to NESO. This analysis is based on the data we have available and our understanding of market behaviour, however, this is limited without visibility of assets outside the BM or market traded positions.

This can create competing control loops for frequency management, as NESO cannot reliably predict the effect its actions will have on non-BMUs which may seek to NIV chase, as NESO does not know (i) the overall volume that might want to NIV chase and where it is located, and (ii) how quickly and how long these units will respond for.

Instances such as on 8 November 2025 can emerge where NIV-chasers overcorrect against the real-time imbalance, typically in response to high imbalance prices, causing an imbalance in the opposite direction. This overcorrection then triggers balancing actions and high prices in the opposite direction, inducing further NIV-chasing.

The oscillation between long and short total market length due to uncontrolled NIV chasing causes a negative impact on frequency and system stability. These cycles can repeat many times until they stabilise. Furthermore, this could distort imbalance pricing, making it harder for market participants to forecast and trade against.

Box 6: NIV chasing under a congested network

Importantly, even if it is assumed that NIV chasing correctly responds to resolve system imbalances perfectly, this would only be effective on an uncongested network. Under a congested network, *where* NIV chasing occurs matters for system operability. A single imbalance price – on a national level – can lead to NIV chasing in the 'wrong' location.

Consider the illustrative example, on a national basis, going short when the system is long can reduce the NIV; however, due to a north-south transmission constraint, instead of supporting the system, if the unit is behind an import constraint, NIV chasing exacerbates the constraint by reducing supply inside an import constrained zone. NESO therefore has to take actions to both resolve the congestion and restore the energy balance, where the latter is effectively to replace the NIV chasing volume located outside the export constrained zone. This represents a greater volume of actions than was initially necessary, increasing costs to consumers and is a misallocation of flexible resources.

Hence, the impact of NIV chasing on balancing the system must take into account the location of NIV chasers on the network and the interaction with network constraints. We show the range of potential scenarios below and the associated impact on balancing the system.

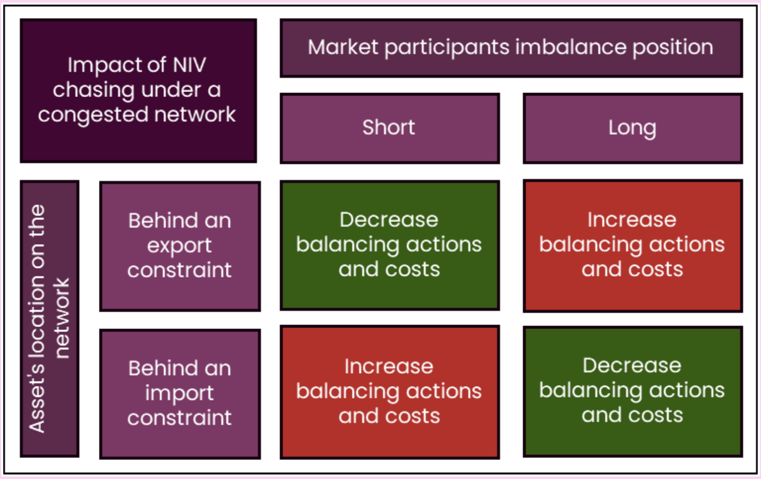


Figure 20: *Interaction between NIV chasing and network*

This highlights two main operability challenges:

- ➔ Getting power in the right place; and
- ➔ Getting the right overall amount of power

NIV chasing under a national imbalance price can support the second objective by reducing the overall energy imbalance on the system but can undermine the first objective as NIV chasers have no incentive to consider localised system needs. The net impact of NIV chasing ultimately depends on the interaction between these challenges.

INTERTEMPORAL OPTIMISATION BEYOND THE BALANCING WINDOW

Issues can arise when NESO needs to take proactive decisions with consequences for future periods beyond Gate Closure, as they overlap with the operation of the intraday market. The greater the re-dispatch needed, the bigger the scale of this problem. These actions can cloud transparency and distort imbalance pricing, making forecasting future requirements more difficult for market participants.

The current market arrangements use a self-scheduling approach, meaning market participants are responsible for start-up and shut-down decisions (known as unit commitment). However, unit commitment decisions taken by NESO through the BM have increased substantially since the early 2000s. It is expected that NESO would take actions which impact periods beyond the balancing window, predominantly to manage system needs such as network constraints or voltage requirements, but also for margin and energy balancing; however, not as significant as is currently observed.[18]

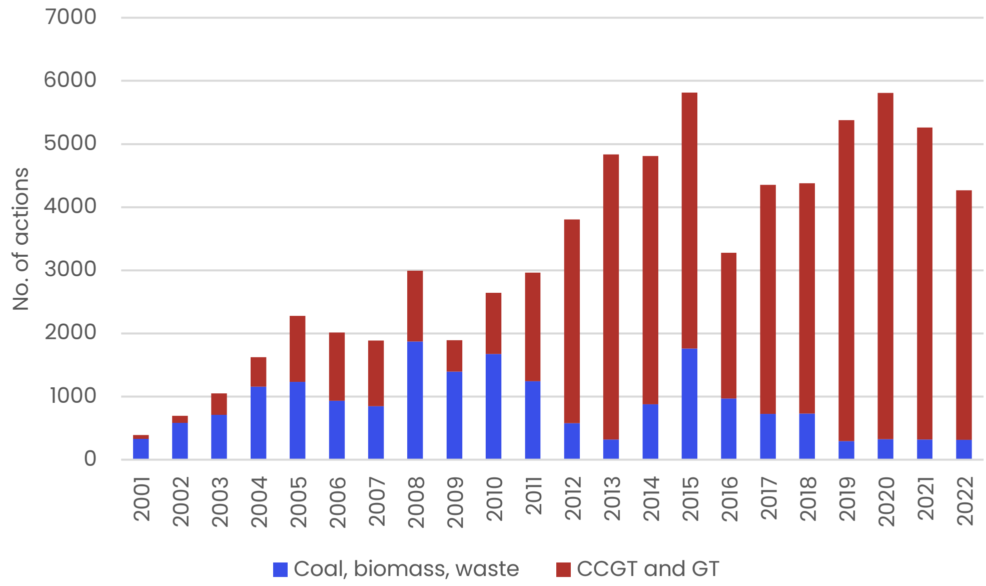


Figure 21: *Unit commitment actions in the BM, 2001-2022. Source: Afry analysis*

Managing intertemporal constraints is an increasing challenge which the BM as a residual balancing tool is not designed for. The use of a simple Bid-Offer structure and dynamic parameters (e.g. Minimum Non-Zero Time and Minimum Zero Time) to represent unit technical constraints and the price of changing a unit's position does not allow market participants to fully express the optionality in running arrangements and costs over time. This prevents more cost-effective solutions for intertemporal optimisation from being identified, ultimately adding costs to consumers.

This is also challenging for energy-limited assets (e.g. a battery), where a decision by NESO to use the asset in the BM changes how much energy is left for the asset to use in subsequent periods. Even with visibility of the State of Charge of energy-limited assets[19], it cannot be certain about the 'usable' energy for future SPs beyond the balancing window.

Taking actions based on the uncertainty of what an asset might do in the future means that both NESO and market participants can miss out on potential value. This is particularly key for storage, as their propensity to intraday trading and flexibility increases the chance that they could have met a system need, but the price signals or mechanism were missing to realise this value.

Ultimately, there is a trade-off between current value (using the asset now to solve an immediate problem) and potential future value (using the asset later to solve an anticipated problem), that can result in inefficient use of storage assets. As a redispatch

[18] Afry (2024) – GB scheduling and dispatch – A case for change

[19] Following operational implementation of GC0166, NESO will receive real-time visibility of an energy-limited assets State of Charge.

market, the BM cannot facilitate effective multi-period optimisation of assets beyond the balancing window, leading to inefficient utilisation of energy-limited assets, and actions which distort the imbalance price and negatively impact transparency.

2.3.4 Distorted wholesale price signals, and incentives to exacerbate system constraints

The misalignment between the national wholesale price and locational balancing needs, along with the scale and predictability of congestion, present significant risks of strategic positioning against constraints. This risk is more likely to arise if the network becomes more congested.

As the wholesale market does not account for the physical limits of the system, NESO must resolve system constraints in real-time through the BM or countertrading, meaning there is a difference in how location is valued between markets, this is shown below. This approach can create operational risk, inefficient dispatch, and distort market participant incentives.

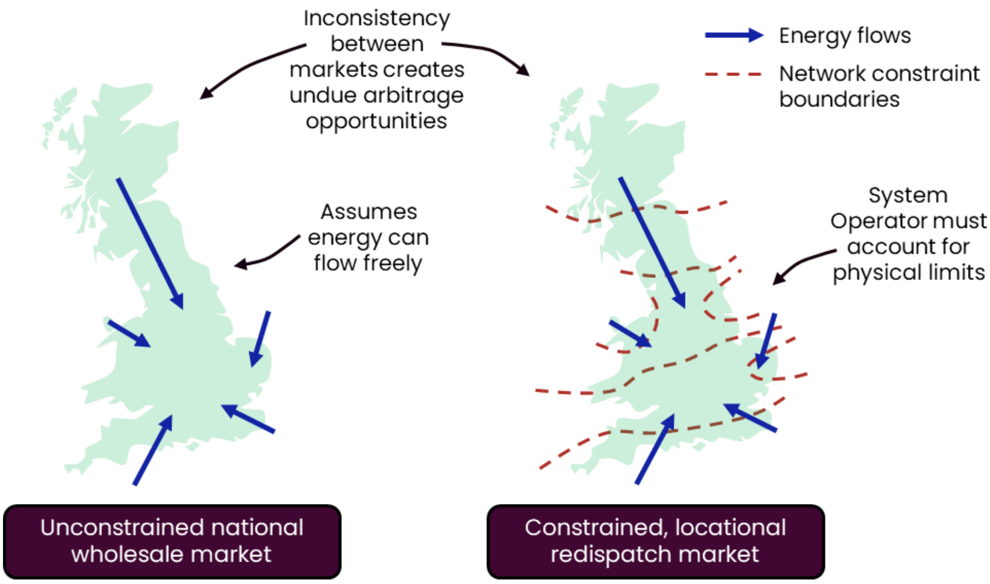


Figure 22: *Inconsistent GB market design between wholesale and balancing*

This could create an incentive for market participants to bid strategically in the unconstrained wholesale market, with the expectation of being redispatched at a better price in the balancing market. For example, a market participant anticipating a higher price in the BM behind a constraint, may undersell their capacity in the wholesale market in order to benefit from higher prices in real-time from redispatch actions.

Market rules exist (for example under the Transmission Constraint Licence Condition) which offer some protection against such behaviour from generators. However, not all strategic conduct of this type will necessarily be captured under these rules, particularly in regard to volumes, and at what point overall profit from constraints become "excessive".

This market behaviour is known in the academic literature as inc-dec (increase-decrease) gaming and has been evidenced in markets with inconsistent locational granularity across markets, i.e. combining a national wholesale market with a locational redispatch market.[20] In GB, Graf (2025)[21] states that growing redispatch volumes due to network constraints *"disincentivizes market participants to schedule their units according to what will be needed in real-time and may even distort long-term investment"*. The incentives for inc-dec gaming in GB have also been observed by Holmberg (2024) and Konstantinidis and Goran (2015).[22]

Box 7: Illustrative example of portfolio-level balancing and perverse incentives for network constraints

Graf (2025) also notes that portfolio-level balancing, i.e. wholesale market bids are not linked to operating units, creates additional challenges for GB. Market participants are responsible for balancing their portfolio contracted positions, but not necessarily in the most efficient way given the physical needs of the system.

Consider the simple example whereby a market participant that has two identical assets, each located at opposite ends of the network, and a portfolio-level traded position of 100MWh for a given period. From a system perspective, the locational value of energy matters significantly due to north to south network constraints. However, this is not reflected in wholesale market prices.

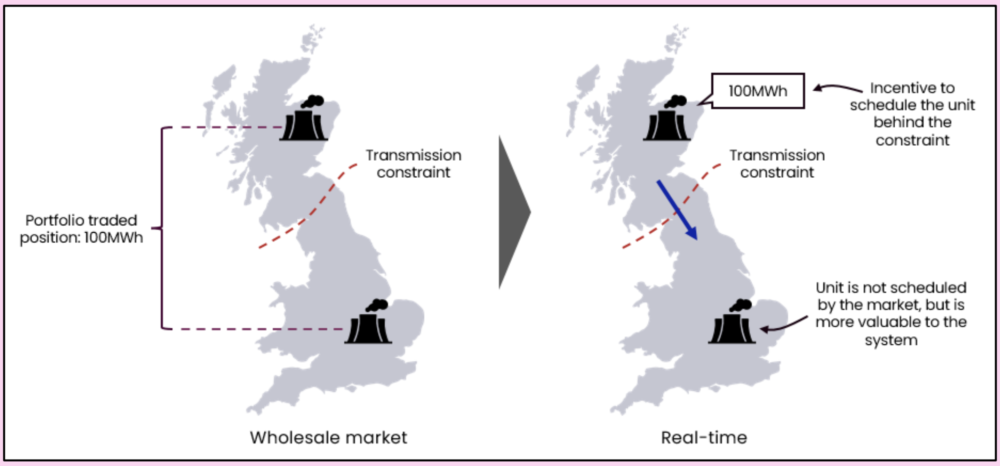


***Figure 23**: Example of portfolio-level balancing and incentives to exacerbate constraints*

Since the market participant could benefit from a redispatch instruction, they may be incentivised to schedule their units in such a manner to aggravate the constraint and trigger a redispatch action. This maximises the market participant's expected market revenue.

[20] Hirth and Schlecht (2019) – Market-Based Redispatch in Zonal Electricity Markets: Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power)
[21] Graf (2025) – Simplified short-term electricity market designs: Evidence from Europe
[22] Holmberg (2024) – The inc-dec game and how to mitigate it; Konstantinidis and Goran (2015) – Empirics of Intraday and Real-time Markets in Europe: Great Britain

Questions on Systems Challenges

Q3. System challenges and causal drivers

To what extent do you believe each of the challenges defined in Section 2.3 contribute to current and future redispatch volumes and costs?

In your response, please comment on:

- Which challenges you consider structural drivers versus secondary symptoms
- Whether any challenges are over- or under-emphasised relative to the others
- Evidence from your operations, experience, knowledge of the market, and empirical or anecdotal evidence that supports alternative interpretations of redispatch growth.

Quantitative section

Q4. On a scale of 1–5, how impactful do you consider the operability and cost challenge from increasing redispatch to be for the GB system over the next 5–10 years?

Q5. On a scale of 1–5, how impactful do you consider the challenge of insufficient visibility of and access to balancing resources (particularly distributed and flexible assets) to be for secure and efficient system operation?

Q6. On a scale of 1–5, how impactful do you consider the challenge of misalignment and overlap between the wholesale market and balancing (including overlapping timeframes and conflicting signals) to be for market functioning and NESO's role as residual balancer?

Q7. On a scale of 1–5, how impactful do you consider the challenge of distorted wholesale price signals and incentives to exacerbate system constraints (including opportunities for strategic positioning around congestion) to be for investment and consumer outcomes?

Scale:
1 = Low impact
5 = High impact

3 Balancing reform

3.1 Proposed Balancing reforms

NESO has considered a wide range of reform options over multiple years and engaged with industry through a series of stakeholder events and requests for input and feedback[23]. This engagement has supported our understanding of the challenges with the current market arrangements, and the potential impacts of reform on market participants.

The proposed balancing reforms have been identified with DESNZ and Ofgem to improve the operational efficiency of the system under a national wholesale market with self-dispatch. The reforms aim to meet, to a lesser or greater extent, the challenges identified in the previous section to ensure the system can be operated in a secure and efficient manner, while delivering cost savings to consumers.

The proposed balancing reforms, as described earlier:

- Lower mandatory BM participation threshold
- Align market trading deadline with Gate Closure
- FPNs must match traded position
- Unit-level bidding
- Shorter Settlement Period

Other reform options we considered in developing the balancing reform package includes a dual imbalance price, scarcity price adder, quasi-PAC (Pay-as-clear) BM, and changes to Gate Closure time. We discuss these options in Appendix 2. It is important to note, however, that these options are no longer being considered as part of RNP balancing reform in the context of progressing the proposed package above.

3.2 Assessment of the balancing reform package

In this section we discuss the proposed balancing reform package against the four challenges. Here, we focus on the design impacts of the reforms and possible trade-offs (e.g. between NESO and market participants) that must be considered. The implementation impacts and, where applicable, the specific design choices of the reforms are discussed in Section 4.

The design impacts discussed below are based on our qualitative assessment of the package, which will support further assessment of the reforms in the next stage of policy development. The proposed balancing reform package will be subject to a CBA, impact assessment, and implementation assessment before a final recommendation is made.

We invite stakeholders to share their views on our assessment of the balancing reforms to ensure all relevant impacts are correctly captured for quantitative assessment and enable robust, evidence-based decision-making.

[23] Please refer to our webpage to find our previous publications and engagement on balancing reform as part of REMA.

3.2.1 Operability and cost challenge from increasing redispatch

TEMPORAL SIGNALS

A **shorter SP** would more accurately reflect the real-time value of energy in the imbalance price, providing more granular temporal price signals for market participants to respond to. This effectively gives greater balancing responsibility to market participants ahead of time and better reveals the value of flexibility to the wholesale market, creating opportunities for flexible assets to manage imbalances between supply and demand.

In turn, shifting imbalance volumes previously resolved in the BM into the intraday market is expected to result in an increase in trading on the intraday market, as market participants are incentivised by more granular, reflective price signals to shape and balance their positions to reduce imbalance exposure.

A longer SP has an "averaging" effect, whereby a market participant can have structural imbalance volumes within the SP and yet have a net imbalance of zero at the end of the period. In contrast, under a shorter SP, while the net energy output is the same, imbalance volumes are significantly reduced.

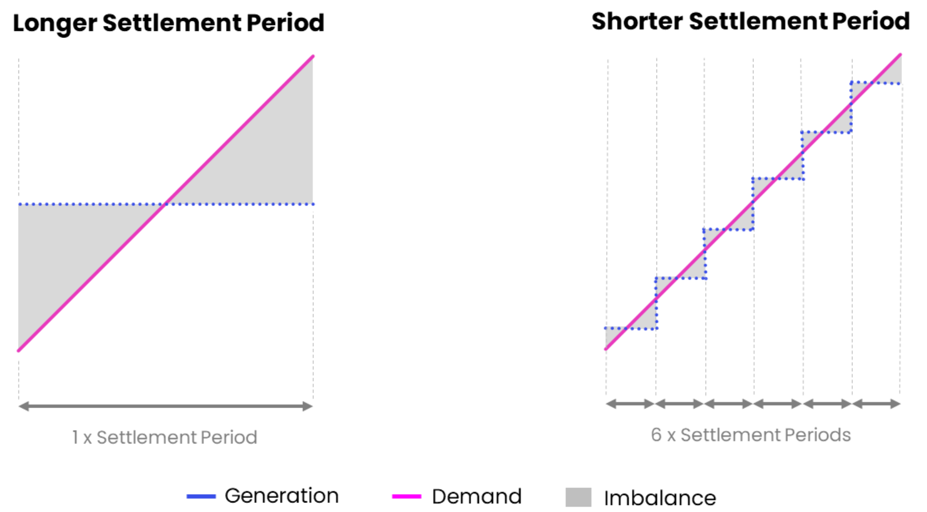


Figure 24: *Impact of Settlement Period length on exposing market participants to imbalance*

Here, structural imbalances are reduced by market participants creating more shape in their traded positions to better match the demand curve and ramping constraints. This directly reduces the volume of balancing actions that need to be taken by NESO in real-time and creates a more reflective imbalance price.

For market participants to be able to manage their imbalance positions at a shorter temporal granularity, they would require equivalently granular products to be offered by Power Exchanges. In GB, a 30-minute product is currently the shortest available to market participants (in line with the current SP length). It is expected that shorter products at both day-ahead and intra-day will follow the implementation of a shorter SP.

However, this does not address intertemporal optimisation for balancing between SPs, particularly in regard to energy-limited assets. As a redispatch market, the BM cannot facilitate effective multi-period optimisation of assets beyond the balancing window, leading to inefficient utilisation of energy-limited assets, and actions which distort the imbalance price and negatively impact transparency.

Box 8: Examples from other jurisdictions

European Union

The Guideline on Electricity Balancing (EBGL) requires EU TSOs to harmonise the SP to 15-minutes, and has already been implemented, among others, in the Nordics, Germany, the Netherlands, and France. Importantly, 15-minute Market Time Unit (MTU) products are currently tradeable across specified borders and within some internal bidding zones on the EU's Single Intraday Coupling (SIDC) continuous market and auctions.

On 30 September 2025, the EU's day-ahead electricity market – the Single Day Ahead Coupling (SDAC) – moved from 1-hour to 15-minute MTUs. The rationale was to enhance market flexibility to enable effective integration of intermittent renewable generation onto the grid, as well demand-side response, and enable TSOs to better balance supply and demand.

Initial analysis has shown that "sawtooth" patterns (typically where prices peak during the initial quarter-hour and drop at the last quarter-hour) remain, driven by the misalignment between hourly generation profiles and actual quarter-hourly output. However, this impact is uneven across countries, with flexible, hydro dominated systems such as in the Nordics showing less sawtooth effects.[24]

Flexible assets, such as batteries, are well placed to benefit from this, with higher volatility and greater arbitrage opportunities to exploit, which can smooth sawtooth patterns. Analysis from Rystad Energy suggests that arbitrage potential has increased by 14% on average across EU markets from the shift to 15-minute MTUs.

Large generation portfolios, and those with thermal generation, have different optimisation challenges that may not be able to take immediate advantage of the 15-minute MTU, which explains why sawtooth patterns may persist, albeit diminished.

Australia

In 2021, Australia's National Electricity Market (NEM) shifted from 30-minute to 5-minute settlement on the basis that granular price signals which align with physical operation supports efficient bidding, operational decisions and investment. Since then, suppliers have been able to offer 5-minute settlement (once the metering data is available) for their customers, increasing the benefits for demand flexibility.

Rystad Energy also find that in Australia's New South Wales state, 5-minute settlement has produced around 20% higher yearly arbitrage revenues than under 30 minutes. Similarly, in Victoria, 5-minute settlement has produced around 15% higher revenues for 1-hour arbitrage since it was introduced.

LOCATIONAL SIGNALS

The proposed reforms, however, do not significantly address inefficient locational optimisation, as without locational operational signals market participants will continue to

[24] Top 5 trends since Europe's shift to 15-minute trading

schedule without regard to network constraints. While opportunities for strategic positioning against constraints could be mitigated, the balancing reforms do not address the core misalignment between wholesale market signals and locational balancing needs.

Given that increasing network congestion is the main driver of redispatch volumes, significant intervention will likely still be required to alter the positions of flexible resources which receive price signals that do not reflect physical realities, where a proportion of this cost to consumers is simply reversing an assets initial contribution to the network constraint.

3.2.2 Insufficient visibility and access to balancing resources

Lower mandatory BM participation threshold

Actions in the BM are sometimes non-locational (e.g. for energy actions) and sometimes locational (e.g. for thermal constraints). Hence, increasing competition in the BM is not a metric that is straightforward to measure, as this can vary over time and across locations depending on the system conditions.

This reform will lead to a direct increase in the number of resources which are visible and accessible to NESO for balancing, increasing the geographical diversity of available balancing resources. It is expected that this will result in downward pressure on BM prices due to increased competition, such that it is cheaper for NESO to balance the system. The effectiveness of this depends on:

- The location of additional participants, as this impacts whether new units can be used to resolve thermal constraints or not (which as explained above are locational);
- The size of the asset pool that would be added to the BM. This in turn depends on factors such as: (i) the chosen threshold limit (a lower threshold would broaden participation); (ii) whether the reform applies to only new assets or would apply retrospectively; and (iii) the pace of implementation.

Lowering the BM participation threshold can support more efficient whole-system optimisation by giving NESO greater visibility of the overall market position and access to a broader pool of balancing resources. With more assets participating directly in the BM, NESO is better able to identify suitable dispatch solutions and coordinate the most cost-effective actions to meet system needs, ultimately reducing costs to consumers.

As an indication of the potential benefits of this reform, an assessment commissioned by NESO's TIDE (Transformation to Integrate Distributed Energy) programme found that improving visibility and access could reduce consumer costs by £3bn over the next decade.

However, this increased visibility, and access must be balanced against potential impacts on Distribution Network Operators (DNOs), as well as impacted assets themselves.

Without effective TSO-DSO coordination, NESO's balancing actions could inadvertently trigger constraints on distribution networks, requiring counter-actions from DNOs, particularly in areas with assets under an Active Network Management (ANM) scheme.[25] This dynamic can also occur in the other direction, i.e. DNO actions impacting constraints on the transmission network.

To mitigate these risks, close collaboration between NESO and DNOs/DSOs will be essential. This includes enhanced real-time data-sharing and improved visibility of distribution network conditions, ensuring that NESO's balancing actions remain operable and do not violate local network constraints, thus supporting efficient whole-system operation.

Secondly, more efficient optimisation of balancing resources also depends on the effective participation of smaller market participants entering the BM. These units would face new operational requirements and costs that may pose a barrier to BM participation, potentially reducing the benefits of lowering the threshold. Therefore, we will build on existing work in this area (e.g. Enabling Demand-Side Flexibility in NESO Markets). It is essential that the BM must be a level playing field for all balancing resources, enabling greater competition.

Other balancing reforms

Competition in the BM could also rise by removing the opportunities and incentives for NIV chasing. **Aligning the market trading deadline with Gate Closure** and ensuring that **FPNs match traded positions**, reduces the scope of this behaviour.

The combination of these reforms could incentivise BMUs to offer more capacity into the BM as previously NIV chasing volume is made available for balancing, and shift energy balancing volumes and liquidity from trading between BM Gate Closure and the start of the SP into the BM.

3.2.3 Overlap between the wholesale market and balancing

There are three areas which jointly address this challenge: (i) Improve operational visibility pre-Gate Closure; (ii) Remove energy balancing by the market post-Gate Closure and strategic imbalance positioning; (iii) Reducing NIV chasing in real-time.

(i) Improve operational visibility pre-Gate Closure

Improving operational visibility ahead of Gate Closure comes from a **lower BM participation threshold** and giving NESO access to aggregated traded positions through the proposed alignment of **FPNs to match traded positions reform**, particularly if combined with **unit-level bidding**.

As discussed, a lower BM participation threshold provides NESO with a clearer view of the intended physical positions of a larger share of the market from more BMUs submitting PNs. This is complemented by giving NESO visibility of aggregated traded positions before Gate Closure which helps close the information gap created by the remaining non-BMUs. This gives NESO a clearer picture of how overall market position evolves throughout the day. However, because non-BMU information is only visible at the supplier's GSP group level, it lacks the granularity available from unit-level PNs submitted by BMUs.

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[25] Primacy rules aim to manage conflicts between NESO and DNOs system requirements. NESO is committed to working with DNOs and the Market Facilitator to establish clear and transparent primacy rules to minimise operational conflicts.

With greater certainty over market positions and more accurate network assessments, NESO could avoid taking unnecessary proactive actions and instead use cheaper, longer-notice balancing actions in a more efficient and coordinated way, helping to reduce costs for consumers.

A key challenge is balancing the flexibility for market participants to self-balance their energy positions with NESO's need for more certainty to operate an increasingly constrained network. Requiring earlier self-balancing may improve NESO's ability to plan secure real-time actions but could also reduce liquidity and leave the market in a less efficient energy position, potentially increasing the volume of balancing actions NESO must take. However, as network constraints become the dominant driver of balancing actions, improved energy balancing alone may not yield more efficient outcomes if it does not align with the physical capabilities of the system.

(ii) Remove energy balancing by the market post-Gate Closure and strategic imbalance positioning

Energy balancing by the market after Gate Closure has the potential to lower the volume of energy actions required by NESO but could also unintentionally lead to higher balancing volumes in situations with high constraint volumes. **Aligning the market trading deadline with Gate Closure** prevents these trades and avoids inadvertently raising balancing volumes and costs. Because the impact of post-Gate-Closure trading is uncertain, NESO must procure more response and reserve to manage the associated risks, adding to consumer costs.

Aligning the market trading deadline and Gate Closure and establishing **a link between FPNs and traded positions** would create a clear delineation in balancing responsibility between market participants ahead of time and NESO in real-time. Together, these measures address strategic imbalance positioning by market participants ahead of real-time:

- Aligning the market trading deadline and Gate Closure removes the opportunity for both BMUs and non-BMUs to trade an imbalanced position after Gate Closure.
- Establishing a link between FPNs and traded positions aims to remove the ability of BMUs to deliberately trade an imbalanced position at Gate Closure.

This removes the risk that NESO takes actions based on FPNs which turn out to not reflect the traded position of market participants. In turn, this should reduce instances of unnecessary and costly balancing actions taken by NESO.

This assumes, however, that BMUs follow their FPNs. If BMUs trade a balanced position at Gate Closure but intentionally deviate from their FPN in real-time to gain exposure to the imbalance price, then the reform would not have the intended effect. Intentionally deviating from FPNs is not permitted and careful monitoring would be required to ensure that this is adhered to.

Box 9: BSC Modification P342 "Change to Gate Closure for Energy Contract Volume Notifications"

The P342 modification was originally justified on the basis that, when combined with the single imbalance price introduced under P305, it would allow parties to submit Energy Contract Volume Notifications (ECVNs) after Gate Closure, thereby enabling greater self-balancing and improving market efficiency.

Having the trading deadline at the start of the delivery period was expected to give participants access to more accurate information on expected cash-out prices and metered positions, helping them align their traded positions more closely with their physical delivery and reducing the imbalance volumes left for the BM to resolve.

However, it was recognised at the time that P342 could also encourage some participants to change their positions after Gate Closure in ways that would have consequential impacts for the SO. Since the approval of P342 in 2017, two system developments have amplified these impacts:

- First, the installed capacity of flexible resources, particularly batteries, has grown dramatically, from 108 MW in 2017 to 6.8 GW in 2025. These flexible, often non-BMU assets, combined with a single imbalance price, have increasingly used the opportunity to trade post-Gate-Closure window to deliberately take net-imbalanced positions, i.e. to engage in NIV chasing.
- Second, thermal constraint volumes and costs have risen substantially. In a system with high constraint volumes and a national intraday and imbalance price, participant actions can inadvertently create rather than resolve local imbalances close to, or in, real-time.

NESO previously established a clear understanding of how we monitor 'Good Industry Practice' on FPN accuracy[26], particularly for wind BMUs, which has improved data accuracy, increased market transparency, and reduced consumer costs.

Building on this work, we ran a Call for Input in October to November last year to gather industry feedback on data inaccuracies that exist within the BM. This work is critical for secure and efficient operations as the system transforms.

However, the proposed reforms may also increase balancing volumes and costs under low-constraint conditions by restricting intraday trading that might otherwise have reduced NESO's need for energy actions. The same applies to measures aimed at reducing NIV chasing, volumes previously resolved by NIV chasers would instead need to be resolved by NESO. The overall impact of limiting post-Gate-Closure energy balancing and NIV-chasing is uncertain and will need to be assessed empirically through the CBA.

(III) Reducing NIV chasing in real-time

Although NIV chasing may reduce the need for some energy-balancing actions, it can increase system-balancing actions when the single national imbalance price does not reflect local network conditions. The reforms therefore aim to reduce situations in which

[26] Guidance Note – Good Industry Practice

more actions than necessary are taken to manage both congestion and the national energy balance — outcomes that ultimately increase consumer costs.

Lowering the mandatory BM participation threshold would help to mitigate reactive NIV chasing by bringing a larger share of resources under BM rules, requiring them to submit and follow PNs. The extent to which this limits the growth of NIV-chasing activity depends on both the threshold chosen and how quickly it is implemented; applying the requirement retrospectively would directly reduce the current proportion of non-BMUs.

Box 10: NIV chasing within a Settlement Period

For example, consider the system is long for a given SP, where the energy imbalance is consistent across the SP. If NIV chasers (1) correctly anticipate the system imbalance, and (2) collectively NIV chased uniformly across the SP, then they would resolve the system imbalance and remove the need for balancing actions.

However, if NIV chasers respond in an uncoordinated way, for example by not taking any action in the first half of the SP, and respond in full in the second half of the SP, the NIV chasers' net imbalance position across the entire SP would be the same, but the within SP imbalance profile would be uneven, leading to an increase in balancing actions and costs.

This is mostly a result of a 30-minute SP which does not provide granular enough temporal price signals for market participants to respond to.[27] A shorter SP would address this by better aligning incentives for NIV chasing (on a temporal basis) with real-time balancing requirements.

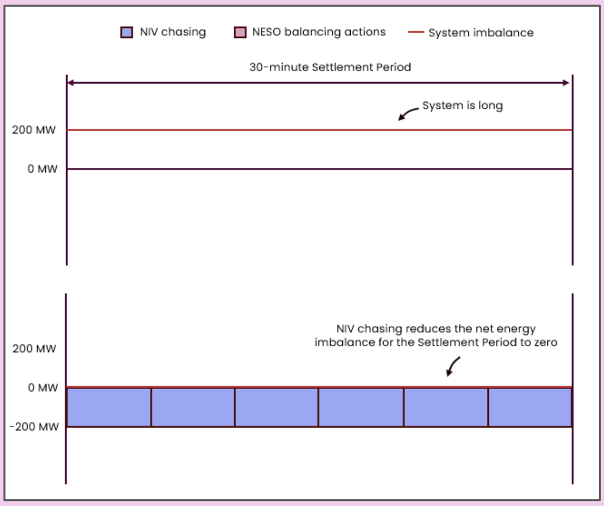


Figure 25: Uniform NIV chasing across a Settlement Period

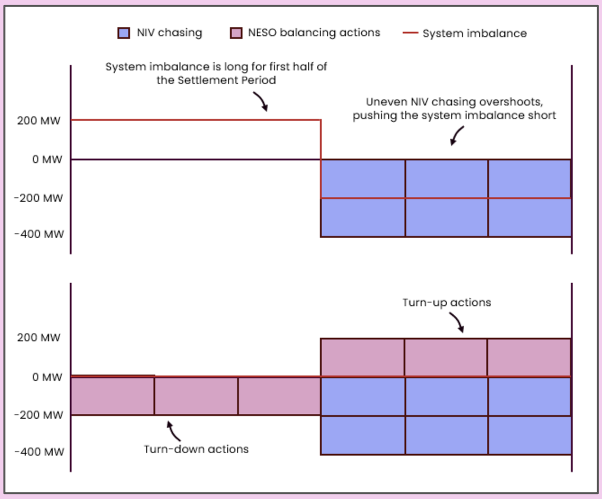


Figure 26: *Uneven NIV chasing across a Settlement Period*

Reducing reactive NIV chasing also limits the competing control-loop effects that can arise when uncoordinated responses cause oscillations between long and short system positions—behaviour that negatively affects system stability. By reducing this instability, the

[27] NIV chasing considers only the net energy position over the entire Settlement Period against the traded position. Therefore, from the NIV-chasers perspective, we can assume that the distribution of the delivered volume within the Settlement Period does not matter.

reform lowers the need for short-duration, high-cost balancing actions and can further reduce NESO's procurement volumes for response and reserve services.

A **shorter SP** complements this by providing a more granular temporal price signal, aligning incentives more closely with real-time balancing needs. This improves the reflectiveness of imbalance prices and supports more efficient trading and operational decisions that contribute to maintaining the system energy balance.

3.2.4 Distorted wholesale price signals, and incentives to exacerbate constraints

The proposed balancing reforms cannot address the misalignment between the national wholesale price and locational balancing needs, nor can they fully address the scale and unpredictability of network congestion that creates opportunities for strategic positioning against constraints.

However, introducing **unit-level bidding** would increase transparency and, in turn, could strengthen Ofgem and NESO's ability to conduct ex-post market monitoring, enabling the identification, and, where appropriate, penalising of such behaviour. This improved visibility can also act as a deterrent, encouraging behavioural change among market participants and reducing the need for NESO to take corrective balancing actions. In turn, this supports a fairer and more efficient market by limiting distortions to wholesale and balancing prices that arise from strategic bidding.

Realising these benefits will require enhancements to the market monitoring function so it can effectively use the unit-level data, and enforcement mechanisms must be applied where necessary.

The impact of this on balancing volumes will depend on:

- The prevalence of strategic positioning against constraints in the market;
- The severity of the penalties (and therefore the strength of the deterrent for market participant misbehaviour); and
- The extent to which greater visibility strengthens the ability to monitor strategic behaviour. For example, it could be easier for Ofgem and NESO to identify instances of commercially irrational behaviour (which could indicate misbehaviour) such as changes in traded position that do not appear to be motivated by a change in prices.

If unit-level bidding data is made publicly available, it could also level the playing field between smaller participants, who already operate close to unit level, and larger portfolio players whose individual unit decisions are less visible. This would support more efficient price discovery and better-informed decision-making across the market.

There are significant design choices in regard to unit-bidding which impacts the degree of potential benefits. Depending on the chosen design, additional scheduling efficiencies could be further unlocked. This is discussed in more detail in Section 4.1.4.

These potential benefits must be weighed against the costs and practical challenges of implementation, as unit bidding could alter trading risk profiles and increase operational overheads for participants—especially those trading predominantly Over-the-Counter (OTC) or those with vertically integrated structures.

Box 11: Additional transparency measures

We have identified two additional transparency measures which we believe could be complimentary to the RNP balancing reform package:

- **Publication of system energy availability**
  Publish real-time State of Energy for storage assets aggregated by key constraint boundaries and published at the unit-level ex-post. This would allow the market to better value and price the remaining storage on the system to facilitate more efficient decision-making. It would also increase our understanding of how total system storage levels impact wholesale prices.
- **History of BM data changes published ex-post**
  Allow market participants to see what options NESO had available in previous periods. The proposal would increase transparency about actions taken with long lead times based on an anticipated need (e.g. running additional units for margin). The transparency is especially important with the high redispatch volumes projected.

3.3 Overall assessment of balancing reform package

Together, the balancing reforms aim to deliver:

- More effective temporal price signals, via a **shorter SP**, to help coordinate market participants across time and reduce structural energy imbalances. This strengthens the value of flexibility in the wholesale market and supports greater use of flexible resources to address energy imbalances and improve supply–demand matching.
- Increased visibility of, and access to, balancing resources for NESO through a **lower BM participation threshold**, enhancing BM liquidity and competitiveness as redispatch needs grow.
- Combining **aligning the market trading deadline to BM Gate Closure** and requiring **FPNs to match traded positions**, could further strengthen incentives to make more balancing capacity available in the BM.
- A clearer division of balancing responsibility between market participants and NESO, enabled by **aligning trading deadlines with Gate Closure**, could reduce unnecessary or counterproductive BM actions.
- Limits on NIV chasing to reduce the risk that this activity worsens network constraints or creates frequency-management challenges that undermine secure system operation. by:
  - **Lowering the mandatory BM participation threshold** to increase the proportion of the market required to submit and follow PNs.
  - **Establishing a link between FPNs and traded positions** to mitigate deliberately trading an imbalanced position at Gate Closure. This would be enhanced if implemented under **unit-level bidding**.
  - A **shorter SP** complements this by providing a more granular temporal price signal, aligning incentives more closely with real-time balancing needs.

- Lastly, **unit-level bidding** could enhance the ability to perform ex-post market monitoring and reduce strategic positioning against constraints, supporting a fairer and more efficient market by mitigating distortions to wholesale and balancing prices arising from such behaviour.

However, this must be assessed against the potential impacts to market operation:

- Without appropriate TSO–DSO coordination, **lowering the mandatory BM participation threshold** could hinder DNOs' ability to manage network constraints, potentially triggering counteractive actions that ultimately increase consumer costs.
- It would also impose additional costs for smaller market participants who would now be required to enter the BM and meet BM operational and compliance requirements
- **Aligning the market trading deadline with BM Gate Closure**, **FPNs match traded positions**, and **lowering the mandatory BM participation threshold** could reduce (i) energy balancing by the market post-Gate Closure (ii) strategic imbalance positioning, and (iii) NIV chasing. However, these same measures could increase balancing actions and costs during periods of low system constraints, as the market may land in a less efficient national energy position.
- Increasing certainty and visibility for NESO to manage redispatch may also reduce market liquidity and limit flexibility through reduced trading opportunities, impacting how market participants manage their positions.
- Lastly, **unit-level bidding** may change the risk profile of some trading strategies and increase ongoing operational overheads for participants, particularly those whose current trading is structured around portfolio-level optimisation.

The net impact of the proposed balancing reforms is ultimately an empirical question to be assessed in the CBA, which will be supported by an impact assessment and implementation assessment to ensure the recommended package is robust and evidence based.

Based on the above sections, we have summarised the theorised impact of the reforms against the balancing and dispatch challenges below. However, it is important to note that this represents our initial, qualitative view of the likely impacts of the reforms. A range of factors may influence this assessment, including the precise design of each reform, the timing of implementation, and interactions between reforms that may not yet be fully captured.

For example, the impact of a lower BM threshold will depend on the specific threshold chosen and whether the requirement applies retrospectively, and the effectiveness of a shorter SP in providing sharper temporal price signals will vary depending on whether a 5-minute or 15-minute duration is implemented.

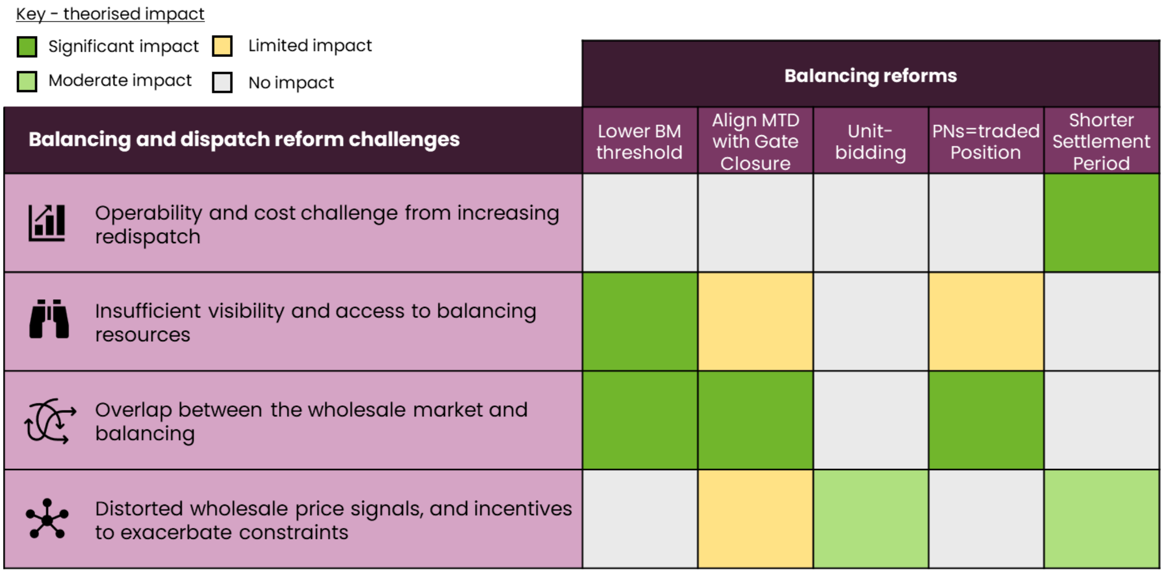


Figure 27: *Impact of the balancing reforms against the challenges*

We observe that the package is most effective against:

- Insufficient visibility and access to balancing resources
- Overlap between the wholesale market and balancing
- Distorted wholesale price signals, and incentives to exacerbate constraints

However, there are some gaps within the remaining challenge:

- Operability and cost challenge from increasing redispatch

While a shorter SP could have a significant impact on energy balancing, it only addresses the temporal value of energy, not the locational value of energy, which is the key driver of redispatch actions. Similarly, a lower BM threshold would enable more efficient optimisation of balancing resources, but it largely addresses *how* we manage high volumes of redispatch.

The volume of redispatch projected under national pricing would necessitate significant NESO intervention into the market by unwinding self-dispatch positions to maintain system security. This is likely to be significantly challenging and inefficient, in turn having a direct impact on consumer bills.

Reforms to balancing arrangements alone cannot address the underlying cause of high redispatch volumes – the level of network congestion that is projected to remain in the system. Nevertheless, such reforms are required to ensure the risks of such high volumes of redispatch can be managed securely and efficiently.

QUESTIONS ON THE EFFECTIVENESS OF THE BALANCING REFORM PACKAGE

Q8. Impact on redispatch volumes, actions, costs:
Do you agree with the interactions and dependencies in the reform package defined in Section 3 to manage redispatch volumes, actions, and costs, do you see any gaps?

In your response, please comment on:

- The volume, timing, cost, and predictability of redispatch actions.
- NESO's ability to act as a residual balancer, rather than a de facto central scheduler?
- Interactions with other reforms, such as P462 or other RNP reforms, that could amplify or diminish their impact on redispatch

Please distinguish between expected impacts in the early transition period and the enduring state.

Q9. Market behaviour and strategic response:

How do you expect market participants' behaviour to change in response to the balancing reform package defined in Section 3?

Please reflect on:

- Changes in trading, scheduling, and risk-management strategies
- Potential new optimisation, arbitrage, or strategic behaviours that could emerge
- Which design features are most important to mitigate unintended outcomes

Q10. Distributional and competitive impacts:

What distributional impacts would you expect across different participant types and technologies as a result of implementing the full balancing reform package defined in Section 3?

Please consider:

- Impacts on generators (by technology), suppliers, storage, aggregators, DSOs, interconnectors, and consumers.
- How this change would affect your business operations (operational practices, trading strategies, and risk management).
- Whether impacts are temporary (transition-related) or enduring for the market operation.
- Where targeted transitional measures may be justified, and where they could create longer-term distortions

QUANTITATIVE SECTION

Q11. On a scale of 1–5, how confident are you that the balancing reform package as described in Section 3 will materially improve operational efficiency and support NESO in managing the four challenges identified in Section 2.3?

Scale:

1 = Not confident

5 = Very confident

4 Implementation Proposal and Initial Impact Assessment

4.1 Balancing package implementation proposal

The RNP balancing package is expected to be implemented as part of an industry-wide programme. We anticipate that the implementation plan will adhere to the principle of delivering benefits as early as possible, while ensuring impacts are proportionate. Where code change is necessary, we expect this to proceed with legislative backing from the Government to support implementation.

The full implementation roadmap will be developed using the outputs of further reform design, feedback from this Call for Input, the CBA, and further impact assessments. The following implementation section is an initial view and remains subject to further revision. We have presented our initial view to test assumptions, assist stakeholders in shaping their feedback, and to enhance the robustness of the CBA and impact assessments.

We strongly encourage stakeholders to share their views on these initial implementation considerations. Your input is vital to ensure we develop an implementation roadmap that ensures the RNP reforms can be delivered effectively.

4.1.1 Lower mandatory Balancing Mechanism participation Threshold

Challenges addressed	Insufficient visibility of, and access to, balancing resources Overlap between the wholesale market and balancing
Options under consideration	• Mandatory BM participation[28] for all electricity assets 1 MW or greater • Mandatory BM participation for all electricity assets 10 MW or greater, with visibility[29] of assets down to 1 MW
NESO's working assumption	• Mandatory BM participation for all electricity assets 1 MW or greater (subject to CBA and implementation assessment)
Implementation approach	Phased implementation which targets market segments by asset size, location, and/or by connection date (e.g. whether an asset is already connected or is a new connection) to accelerate the realisation of benefits. Phases will align to critical system and process development milestones, for example: • Phase 1: Lower mandatory BM threshold in line with the maximum throughput of current systems and processes (e.g. mandatory threshold is lowered to 30 MW) • Phase 2: In-flight system changes and the first tranche of additional process improvements deliver, allowing for a further reduction of the lower mandatory BM threshold (e.g. mandatory threshold is lowered to 10 MW) • Phase 3: Enduring solution is delivered, allowing for the final reduction of the mandatory threshold (e.g. mandatory threshold is lowered to 1 MW)
NESO suggested implementation timeline	Current thinking is an overall timeline starting in 2027 with phasing to be determined following the Call for Input and Cost Benefit Analysis

The Grid Code requires that BM Units submit PNs to NESO if their Generation or Demand Capacity is at or above 50 MW in England and Wales, 30 MW in South Scotland or 10 MW in North Scotland. It is optional below these limits. Submission of PNs provides NESO with **visibility** of BMUs physical position such that we can plan and issue the required actions ahead of the SP start.

As stated before, the goal of lowering the mandatory BM threshold is to increase the volume of assets that are accessible to NESO for balancing purposes, particularly DERs, and improve

[28] BM participation refers to submitting the full set of BM parameters (PN, MEL/MIL, SEL/SIL, ramp rates, bid/offer pairs etc.) and being bound by the relevant Grid Code obligations.
[29] Visibility in this context would mean adhering to the full set of BM participation requirements stated above other than the submission of bid/offer pairs and responding to BOAs.

visibility through the mandatory submission of and adherence to PNs of all impacted assets as well as real-time metering. We believe that the appropriate goal is for all generation assets that are 1 MW or greater to be registered in the BM, though we recognise that there may be challenges in achieving this. The 1 – 10 MW generation asset population may include segments of the market that are less operationally ready to adopt additional BM requirements, such as smaller providers operating on export tariffs, or non-domestic consumers with on-site generation. Inclusion of these assets would also significantly increase the amount of data that NESO and Elexon would need to process.

Lowering the mandatory BM threshold is not a new concept. Grid Code Modification GC0117[30] (raised in 2018) proposes to align the definitions of 'Large' power stations across England, Scotland and Wales, one effect of which would be lowering the mandatory BM threshold to 10 MW. NESO's Transformation to Integrate Distributed Energy (TIDE) programme has worked with DSOs to explore methods of improving TSO/DSO coordination. Our Power Responsive[31] programme recently published the Operational Metering Requirements final report[32], which reviewed BM operational metering requirements and set out recommendations to modernise them.

The RNP proposal to lower the mandatory BM threshold is separate to GC0117 and not dependant on its outcome.

Initial Implementation Considerations

We believe that to accelerate the realisation of benefits, migration of generation assets into the BM should be phased and target generation assets based on size, connection status, and connection date. To explore the lower mandatory BM threshold implementation impacts we have outlined an example phased delivery approach.

Lowering the BM Threshold is expected to introduce additional process and technical requirements to central parties (e.g. NESO, Elexon, DSOs) and market participants responsible for impacted generation assets (e.g. those 1 MW or larger) that have future connection applications, that have been assigned a connection date, or that have been connected in compliance with Engineering Recommendation G99 (EREC G99)[33] (after 27 April 2019). Some older assets that do not comply with EREC G99 may be required to migrate into the BM, subject to system needs. In discussing the initial implementation considerations, we have assumed the following:

- Implementing functional changes to central systems that manage balancing, forecasting, and settlement will be necessary to manage increased data volumes. In-flight technical developments such as NESO's Open Balancing Platform (OBP) and Elexon's HELIX and Data Integration Platform are expected to reduce this impact.

[30] GC0117: Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Station requirements
[31] NESO Power Responsive.
[32] NESO & DNV: Operational Metering Requirements (September 2025)
[33] EREC G99

- Migration of assets into the BM is expected to introduce the need for additional process reform. For example, the Grid Code and the BSC processes associated with BM registration processes may require updating.
- BM participation will increase cost overheads for units impacted by the new threshold. There is potential for these impacts to be reduced through work being progressed in the BM wider access[34] workstream.
- Enhancing TSO/DSO coordination will be critical in ensuring efficient whole system operation. NESO, the Market Facilitator and DSOs will continue to work together to accelerate the delivery of the future TSO/DSO operating model and define the primacy, stacking, data sharing, and technical infrastructure requirements.
- Implementation will be phased to accelerate the rate of assets migrated into the BM, providing NESO earlier visibility and access to DERs. Phases are expected to align to critical system and process development milestones and to target market segments by asset size and/or connection date.
- Detailed design will include a review of relevant regulatory and operational processes to ensure that transitional and ongoing arrangements are appropriate. This is expected to focus on the arrangements that are sub 10 MW to ensure that impacts are proportionate. This may include exploring alternative BM access routes for smaller units, such as via a Virtual Lead Party (VLP).
- A single set of code modifications will be developed to cover all implementation phases.

The implementation methodology outlined below (see Table 1) illustrates how we might define implementation phases to maximise the volume of units actively participating in the BM, while managing industry and central party impacts.

Impacts on Industry

The following is a list of transitional and enduring impacts of the reform on industry bodies as well as market participants identified in a preliminary analysis. These impacts are subject to change as decisions around policy and market design are made. For further information on impacts please refer to Appendix 3: Impact Tables.

- Increased volumes of BM registrations and associated process changes. Once registered as a BMU, there will be ongoing operational requirements to comply with BM rules, such as submitting Bids and Offers, and PNs and other BM data.
- Migration of embedded/queued assets into BM, including connection offer revisions
- Real-time data sharing, SCADA and metering upgrades
- Changes to operational planning, balancing and forecasting systems to handle higher volume and granularity
- Access to new commercial opportunities from BM participation and improved data sharing

[34] NESO Balancing Mechanism Wider Access

Table 1: *Lower BM mandatory threshold phasing implementation proposal*

	Phase 1	Phase 2	Phase 3
Description	Increasing the volume of BMUs to the maximum practical throughput of existing systems and processes. For example: • Reducing threshold to 30 MW for newly connected assets (considering existing assets with a connection offer)	Delivery of in-flight NESO system changes (e.g. OBP, NCMS), also the expected approval of GC0117 and first tranche of new capabilities will further increase the throughput potential, allowing for a further reduction of the BM threshold. For example: • Reduce threshold to 10 MW for newly connected assets (considering existing assets with a connection offer)	Deployment of enduring solution, including functional system changes, updated processes, additional tools and capabilities, allowing for: • Threshold to be reduced to 1 MW for all newly connected assets Retrospective migration of assets installed post EREC G99 (27 April 2019)
Changes Expected	• Update regulatory codes (e.g. Grid Code, Connection Use of System Code (CUSC) & BSC) with transitional and enduring rules • Increased operational and registration activity for NESO and Elexon • Potential increased effort to make new assets Supervisory Control and Data Acquisition (SCADA) ready at the point of connection • Higher interaction with Active Network Management (ANM) systems. Work alongside the Market Facilitator to codify Primacy before phase 3 • Updates to existing connection offers and technical limits • Potential introduction of additional transitional arrangements to support migration of assets with existing connection offers • Workstream to define the enduring TSO/DSO operating model and coordination processes commences	• Delivery of inflight changes to core NESO and Elexon systems (e.g. Open Balancing Platform (OPB) and Helix) • First delivery of updates to key processes (e.g. BM registration) • First deployment of updated TSO/DSO coordination processes and rules. Workstream continues to develop the enduring solution to be delivered in Phase 3 • Updates to connection offers and review of technical limits	• Enduring capabilities and tooling for DSO-TSO data sharing are delivered (e.g. visibility of network models, real-time network information). • Implementation of final TSO/DSO coordination framework, rules and processes (primacy/revenue stacking) in conjunction with the Market Facilitator • Final deployment of changes to central systems (e.g. NESO and Elexon systems) • Programme in place to manage retrospective migration
Assumptions	• There is additional throughput within existing processes and systems, and no additional capabilities are required to manage increased volumes in this Phase. • Further consideration will be given to how changes to existing connections offers will be managed, to ensure impacted parties have sufficient time and support to meet the additional BM registration requirements. • Further design activities will be progressed ahead of, and during phase 1, to define the enduring system operating model (e.g. primacy and stacking rules)	• Functional and capability changes for 10 MW threshold are deployed. • Further reduction of the mandatory BM threshold can be progressed without deployment of the enduring TSO/DSO coordination tools. • Transitional arrangements are required to support the integration of assets with existing connection offers • GC0117 will be approved and implemented by 2028. Further assessment on interactions with GC0117 and subsequent modifications that would apply GC0117 retrospectively is required • Market Facilitator, NESO, and DSOs will resolve and agree final coordination framework.	• Enduring technical solution and processes are deployed. • Retrospective application will be phased, first targeting larger assets and will be limited to assets complying with EREC G99 (27 April 2019), such that operational metering requirements are met. Some older assets could be required to comply with EREC G99, subject to NESO requirement.

QUESTIONS ON LOWER MANDATORY BM PARTICIPATION THRESHOLD

Q12. Cost, benefits and implementation impacts

What implementation and ongoing costs should NESO consider associated with lowering the mandatory BM threshold reform, and what operational benefits or opportunities do you expect?

Please comment on:

- Implementation timelines and associated costs, including feasibility of phased rollout, retrospective application and target BM threshold.
- Which asset types or business models face the most material implementation and operational cost impacts, and where the reform may generate net benefits across your portfolio.
- How the reform would change your cost exposure when providing or using flexibility services.
- Interactions with DSO flexibility arrangements or flexible connection agreements that may increase or decrease costs or benefits.

Q13. Proportionality and implementation:

What barriers or challenges might smaller participants encounter with implementation? What steps could be taken to manage impacts, while ensuring the stated objectives of enhanced visibility and access are achieved?

Please comment on:

- Proportionality of compliance requirements
- The role of aggregators or alternative access routes
- Transitional arrangements/incentives to support parties in meeting BM obligations
- Any specific risks to competition or market access that we should consider

QUANTITATIVE SECTION

Q14. On a scale of 1–5, how confident are you that lowering the mandatory BM participation threshold will significantly improve visibility and access to balancing resources, while remaining proportionate in terms of costs and obligations?

Scale:
1 = Not confident
5 = Very confident

4.1.2 Aligning market trading deadline with Gate Closure

Challenges addressed	Insufficient visibility of, and access to, balancing resources Overlap between the wholesale market and balancing Distorted wholesale price signals, and incentives to exacerbate constraints
Options under consideration	• Realign market trading deadline with Gate Closure, in effect reversing BSC Modification P342
NESO's working assumption	• Realign market trading deadline with Gate Closure (subject to CBA and implementation assessment)
Implementation approach	• Single Implementation
NESO suggested implementation timeline	• Implementation starting in 2027

Gate Closure is when the PNs submitted by BMUs to NESO become final and cannot be adjusted. It is currently one hour before the start of the SP. The market trading deadline (or submission deadline) is when participants must submit their contracted positions to Elexon. These contract positions are Energy Contract Volume Notification (ECVNs)[35] and Metered Volume Reallocation Notifications (MVRNs)[36]. The deadline is currently aligned with the start of the SP, though in practice the main intraday continuous market closes 15 minutes prior to the start of a SP. Before 2017, they were aligned at one hour ahead of the start of the SP until changed by BSC modification P342.

The proposed design of this reform would be to undo the P342 change and realign the market trading deadline with BM Gate Closure, at one hour before the start of the SP. For completeness, this reform does not propose moving Gate Closure, either earlier or later.

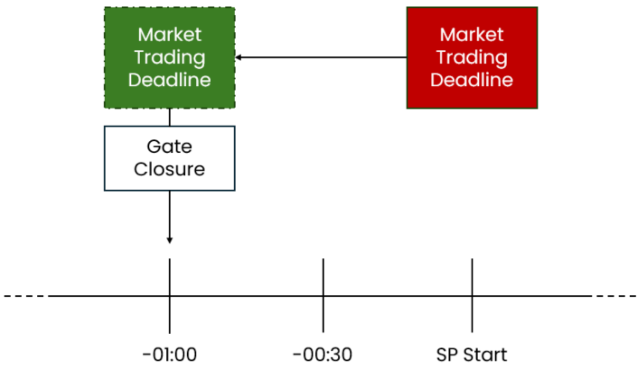


***Figure 28**: Aligning Market Trading Deadline with Gate Closure*

[35] ECVNs notify Elexon of the volumes of energy bought and sold between two Energy Accounts. These Energy Accounts could belong to separate Parties or could both belong to the same Party

[36] MVRNs notify Elexon that the energy flowing to or from a particular BM Unit is to be allocated to one or more different Party's Energy Accounts for the purposes of Energy Imbalance calculations.

Initial Implementation Considerations

BSC P342 was used as a benchmark for our initial implementation assessment, as this reform is effectively a rollback of that code modification. In contrast to P342, this reform reduces market participant's trading opportunities rather than providing an opportunity to expand them. As such, there is a potential for this reform to have a more significant impact to market participants. However, we still anticipate expect a low-medium implementation effort, considering the following assumptions:

- Current expectation for implementation is assumes similar timescales to P342, which was implemented in 9 months following Ofgem's approval in 2017, this will be refined after industry feedback.
- Market participants (particularly intermittent generation) likely to place additional emphasis on intraday forecasting because the option to trade post gate closure will be removed.
- Changes to the BSC can run in parallel with system and process changes for market participants and power exchanges.

Impacts on Industry

The following is a list of transitional and enduring impacts of the reform on industry bodies as well as market participants identified in a preliminary analysis. These impacts are subject to change as decisions around policy and market design firm up. For further information on impacts please refer to Appendix 3: Impact Tables.

- Market Participants will be required to update trading strategies and notification systems to comply with new market trading deadline.
- Greater need for improved forecasting accuracy at Gate Closure to manage exposure to imbalance.
- Elexon will be required to undertake changes to the Energy Contract Volume Aggregation Agent (ECVAA) and other central systems in line with the new arrangement.
- Power exchanges will be required to update their platforms to adhere with the new trading deadline. Impact to be limited to the continuous intraday market.
- Potential impact to near real-time flexibility, requiring improved coordination between flexibility markets and the BM.

Questions on Aligning Market Trading Deadline with Gate Closure

Q15. Risk allocation and market functioning:

How would aligning the market trading deadline with gate closure reallocate forecast, imbalance, and operational risk between market participants and NESO?

Please consider:

- Impacts on trading liquidity and intraday risk management
- Current use of post-gate-closure trading
- Effects on different technologies and business models
- Whether the reform strengthens or weakens the clarity of balancing responsibility

Q16. Implementation timelines, costs and transition considerations

What implementation and ongoing costs should NESO consider associated with aligning the market trading deadline with gate closure?

Please comment on:

- Implementation timelines and costs of adapting trading systems and internal processes to an earlier deadline.
- Cross border or contractual factors that may increase cost or extend implementation timelines.
- Any ongoing cost implications of the change.

Quantitative section

Q17. On a scale of 1–5, how confident are you that aligning the market trading deadline with Gate Closure will improve clarity of balancing responsibility and reduce inefficient overlap between market trading and NESO balancing actions?

Scale:
1 = Not confident
5 = Very confident

4.1.3 Final Physical Notifications to Match Traded Positions

Challenges addressed	Insufficient visibility of, and access to, balancing resources Overlap between the wholesale market and balancing
Options under consideration	• NESO receives the aggregated market positions • Market participants must match FPNs and traded positions (under portfolio bidding or unit bidding arrangements)
NESO's working assumption	• To be determined based on CBA and implementation assessment.
Implementation approach	• Implementation approach will differ between portfolio bidding or unit bidding arrangements. Subject to further assessment based on CBA results and Call for Input feedback.
NESO suggested implementation timeline	• Under portfolio bidding: Implementation starting in 2027 • Under unit bidding: to be determined with unit bidding implementation timeline

The FPN matching traded positions reform is expected to have different impacts and benefits under portfolio or unit bidding arrangements. Our initial assessment indicates considering FPN matching traded positions alongside unit-level bidding delivers greater benefits, and further consideration of the design of the reform would be required if portfolio-bidding is retained. Overall, the proposed reform aims to provide NESO with improved operational visibility, mitigate strategic imbalance positioning, and subsequently, more efficient redispatch decisions.

Below we set out the possible implementation options under consideration for this reform:

Scenario 1: Portfolio Bidding Arrangements

1a: Enhanced market traded position visibility without matching FPNs to traded positions

In this scenario we are aiming to increase visibility for NESO of the aggregated market traded position by SP ahead of Gate Closure. This would provide NESO with greater situational awareness and seeks to address the current visibility gap between what can be observed through FPNs and the overall market traded position to support more effective dispatch decisions. NESO currently only gets advanced information on the expected position of BMUs in the form of PNs and FPNs; we do not see ahead of time what position market participants have actually traded. However, these changes would not serve as a deterrent to NIV chasing.

Improving NESO's visibility of the market position would require the provision of an aggregated market traded position to NESO, e.g. from day-ahead until Gate Closure. This may require additional obligations on market participants to ensure a timely and complete submission of traded positions. Further development of the aggregated market position calculation methodology is required to ensure an accurate representation can be provided to NESO.

Further assessment on the implementation of the proposal will be addressed after receiving the feedback through the current Call for Input and further CBA assessment.

1b: Market Participants must match FPNs to traded positions at a portfolio-level

In this scenario market participants are mandated to submit FPNs that match their traded positions at a portfolio-level by SP ahead at Gate Closure, as well as visibility for NESO of the aggregated market traded position by SP ahead of Gate Closure.

Further assessment on how this proposal will link FPNs and traded position at a portfolio-level, and how this impacts the proposal effectiveness, will be addressed after receiving the feedback through the current Call for Input and further CBA assessment.

Scenario 2: Unit Bidding Arrangements

In this scenario, market participants are mandated to submit FPNs that match their traded positions at a unit-level by SP ahead at Gate Closure, as well as visibility for NESO of the aggregated market traded position by SP ahead of Gate Closure.

Under unit bidding we anticipate that obligations for FPNs to match traded positions would apply to all units which submit PNs, including Supplier PNs (which are assumed to remain on a GSP Group level).

Implementation Considerations

We recognise market participants face different challenges and uncertainties with respect to expected generation or demand in real-time. Therefore, it may be appropriate to consider tolerance levels or different considerations by technology, for example due to physical restrictions on the generation units, while ensuring the reform achieves the stated objectives.

Another key consideration is when FPNs must match traded position. Our current view is that FPNs must match traded position at Gate Closure, regardless of whether the change to align the market trading deadline with Gate Closure proceeds.

The overall impact will depend on whether a financial or physical unit bidding design is adopted (see Section 4.1.4). Nonetheless, we expect that market participants would need to revise their internal processes, systems, and trading strategies to ensure alignment between their final market position and FPNs at a unit level.

Compliance Options

There are several compliance options available for monitoring FPNs matching traded positions, each with varying implications for both central systems and market participants. Our initial assessment identified the following options:

- Post-event compliance could be monitored and enforced through the BSC and its Performance Assurance Board, or by NESO via the Grid Code assurance processes.
- Pre-event compliance could be assessed immediately after FPN submission at Gate Closure, and fed into the BSC, or Grid Code assurance processes. This would require

the introduction of additional tools to facilitate monitoring within the balancing window and is likely to be more straightforward with unit bidding
- Alternatively, Ofgem could monitor compliance and apply financial penalties for deviations.

Impacts to Industry

The following is a list of transitional and enduring impacts of the reform on industry bodies as well as market participants identified in a preliminary analysis. These are impacts under Scenario 1 (Portfolio Bidding) and are subject to change as decisions around policy and market design firm up. Impacts for Scenario 2 (Unit Bidding) would be explored in further analysis. For further information on impacts please refer to Appendix 3: Impact Tables.

- Market participants may be required to progress updates to processes and systems associated with sending contracted energy volumes (ECVNs and MVRNs) to ensure that Elexon has the necessary data to calculate the aggregated traded position ahead of Gate Closure.
- Market Participants may be required to enhance near-real time forecasting capabilities to ensure FPN accuracy and manage imbalance risk.
- Market participants may be required to increase their risk management capabilities, due a probable greater exposure to cash out prices, given the requirement of matching their traded position with their FPN.
- Aggregated BMUs, such as those managed by VLPs, or Supplier BMUs may be exposed to a greater non-compliance due to the relative complexity of accurately forecasting aggregated units.

Questions on Final Physical Notifications Matching Traded Positions

Q18. Costs, benefits and implementation feasibility of FPN to match traded positions

What implementation and ongoing costs should NESO consider associated with implementing FPNs to match traded positions?

Please comment on:

- Implementation and ongoing costs, including system changes, forecasting processes, and compliance requirements.
- Differences in cost and implementation timelines between portfolio level and unit level approaches.
- How differing technologies within a portfolio may affect the complexity, cost, and practicality of implementing the reform.

Q19. Risks, tolerances, and exemptions:

What risks or unintended consequences could arise from the different scenarios proposed for FPN to match traded positions under portfolio bidding or unit bidding, and how should tolerances or exemptions be designed?

Please comment on:

- Technology-specific and contract structure differences.
- Potential gaming or risk-shifting behaviours.

- Governance and enforcement considerations during transition.
- Whether obligations should differ between aggregated portfolios and disaggregated unit-level positions.

Quantitative section

Q20. On a scale of 1–5, how confident are you that requiring FPN to match traded positions will improve forecasting accuracy, transparency, and NESO's operational confidence, without creating disproportionate implementation or compliance risks?

Scale:
1 = Not confident
5 = Very confident

4.1.4 Unit-level bidding

Challenges addressed	Distorted wholesale price signals, and incentives to exacerbate constraints
Options under consideration	• Retaining portfolio-based bidding (counterfactual) • Physical unit bidding • Financial unit bidding
NESO's working assumption	• To be determined based on CBA and implementation assessment.
Implementation approach	• Implementation approach will be assessed following the Call for Input feedback and CBA analysis.
NESO suggested implementation timeline	• Implementation timeline will be determined following the Call for Input feedback and CBA analysis.

Unit bidding would provide more information for an efficient power system operation, enhanced market monitoring for a fairer market, and would facilitate more effective implementation of the FPNs matching traded positions reform.

Unit bidding means that market participants would need to provide bids and offers in the form of price-quantity pairs for all BM Units traded in wholesale markets. Parties not participating in the BM would continue to bid into wholesale markets at an aggregated level with suppliers expected to bid at the Supplier BMU granularity (i.e. by GSP group). The price, volume and unit information would first need to be provided at the day-ahead stage (i.e. around 9:30 on the day before delivery) and updated to reflect intraday trades. This means that under any version of this proposal, portfolio trading would be retained in some form until the Day-Ahead Market (DAM) stage.

In this Call for Input, we explore two ways in which unit bidding could be implemented:

- Option 1: Retention of a physical forward market with ECVNs assigned to specific units at the day-ahead stage (and updated at unit-level for intraday trades).
- Option 2: Conversion of forward trading to financial trading coupled with bidding into a new, singular, gross pool DAM to gain a physical position.

While we expect Option 1 would be easier to implement than Option 2, the resulting pricing information could be less robust such that the potential benefit may be less than in Option 2. Furthermore, Option 2 could deliver greater benefits by providing a higher level of quality of bids and offers.

Option 1: Physical

Under Option 1, the current market arrangements would remain unchanged until the day-ahead stage. At this point, market participants would disaggregate their net portfolio positions to specific units. This would apply to any positions secured through a power exchange, OTC, or within vertically integrated portfolios. We would not expect this option to negatively affect the flexibility of trading – while parties would assign trades to individual

BMUs after DAM results are published by Power Exchanges, their obligation to deliver would be unchanged. They would still be able to move volumes within portfolios via further trades or MVRNs.

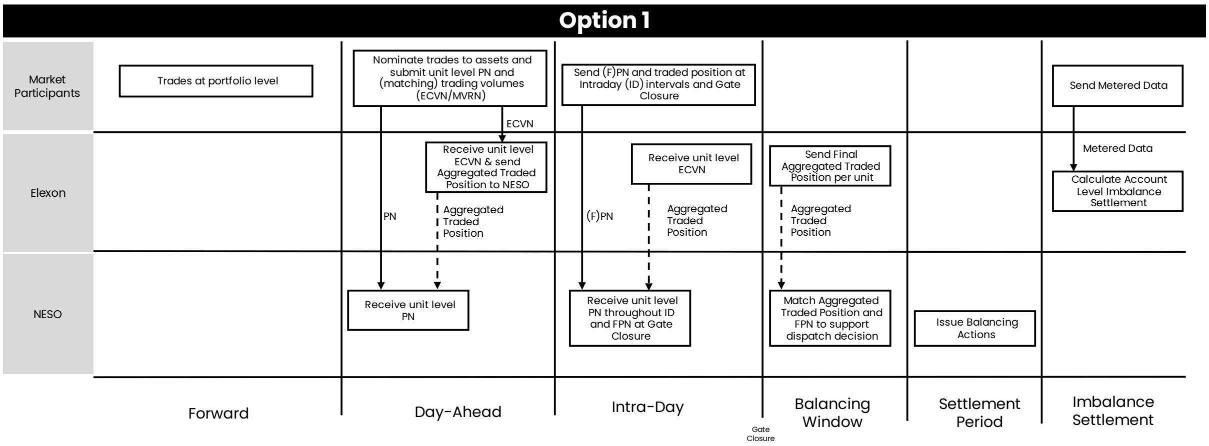


Figure 29: *Process diagram for unit bidding Option 1*

This option would retain simple trading formats such that market participants would link their traded volumes to individual BMUs via price-quantity pairs. The precise nature and format would be agreed in consultation with industry. This could include differentiated prices and/or more complex bid and offer formats reflecting technical and commercial parameters if there was a downstream application for this (e.g., more sophisticated forecasting and scheduling). The intent is that trading parties could still change the composition of their portfolio across the day as long as PNs, ECVNs/MVRNs and disaggregating price-quantity pairs are updated appropriately.

This option ensures that market participants can still access a physical position in forward markets, but ensures that NESO, Elexon, and Ofgem could receive complete price-quantity data at the day-ahead stage to address the challenges discussed in Section 2. Specifically, this option could provide NESO with a more robust picture of locational market position and future commercial decisions such that NESO's pre-Gate Closure decisions could be optimised with better information. The decisions that could benefit and be cheaper for consumers include response and reserve procurement, synchronisation instructions for inflexible units, Schedule 7A trades[37], the Demand Flexibility Service, and Local Constraint Market. Further, the enhanced transparency around the position and economics of specific assets could highlight strategic positioning ahead of real-time.

Option 2: Financial

Under Option 2, the DAM would operate as a gross pool[38] and be the main route for market participants to secure a physical position. Further opportunities would come via centralised

[37] Ahead of the BM, NESO can trade with market parties. Schedule 7A sets out the provisions for BM Unit Specific Transactions. This enables NESO to agree a trade to either increase or decrease their output to a specific volume for an agreed price and time.

[38] A gross pool is a market where all physical positions are bought and sold through a common pool. Examples include Australia's National Energy Market (NEM) and Pennsylvania-New Jersey-Maryland's (PJM) real-time market.

intraday trading, the details of which will be confirmed through upcoming policy development, supported by the responses to this Call for Input. All volumes seeking a physical position would bid into the gross-pool DAM and the optimal economic resource mix would be clear through optimisation processes. This contrasts with the net pool concept[39] which is currently in place in GB day-ahead trading. Market participants would still have full control over the prices and volumes they submit.

Similar to Option 1, all trading prior to the DAM could remain at a portfolio level. We would expect such bilateral trading and futures to continue via financial contracts settled against a reference price, such as the outcome of the DAM. As this trade would no longer be physical it would be accessible to additional financial entities who may be interested in trading the commodity.

Under a gross pool, the DAM would clear at a level to satisfy supplier demand on an unconstrained basis. We would expect the demand side to be based on supplier demand (as expressed via bids, or via PNs submitted for Supplier BMUs). The market would clear at a level that satisfies the demand expectation and successful units would acquire a physical position. Therefore, a supply and demand curve would be based on aggregating all bids and offers into the gross pool, and any trades below the equilibrium price would be cleared (accepted).

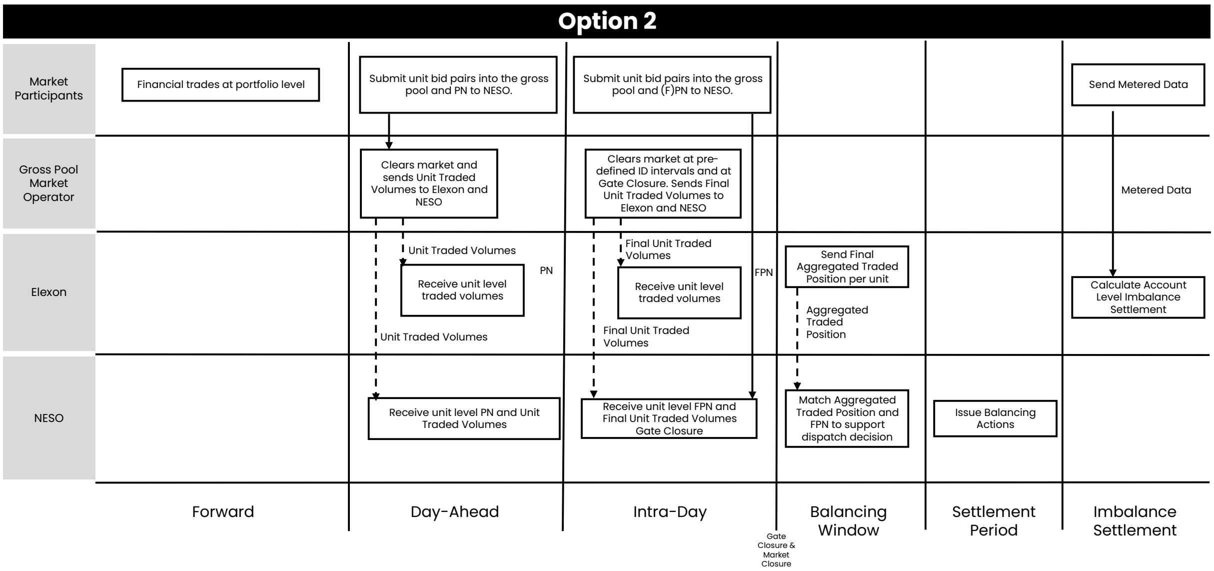


Figure 30: *Process diagram for unit bidding Option 2*

The market clearing would be similar to the existing power exchange auctions.[40] The solution would reflect an unconstrained network such that NESO would still be required to redispatch units to resolve physical system constraints.

[39] A net pool is a voluntary market where participants typically trade surplus, or deficits relative to their bilateral contracted position.

[40] A key difference would be that while the auctions are currently split between different power exchanges and timeframes, and only clear the portion of the market, there would only be one gross pool DAM and it would be compulsory.

Alternative bidding formats, such as Scalable Complex Orders or 'multi-part' offers, would be an important part of participating in a gross pool, to ensure that asset parameters can be respected when clearing the market. This will be essential in preventing unfeasible schedules, such as asset clearing at a volume lower than their Stable Export Limit (SEL).

The primary benefit of the gross pool relative to Option 1 is that by providing a single DAM as the first point at which participants can trade physically, liquidity would be maximised and all participants would have the best opportunity to secure a fair physical position, regardless of their size. System costs could be reduced via this process to identify the economically optimal resource mix.

On the other hand, moving to a gross pool may increase (relative to Option 1 and the status quo) the operational overheads, including increased collateral requirements associated with a move to financial-forward trades, for market participants who primarily trade OTC and parties who are vertically integrated. Market participants have also previously raised concerns over liquidity in financial-based forward markets versus physical-based ones. Option 2 could introduce additional risk for operators if the gross pool causes some units to be committed earlier than a generator might have chosen under the existing market. However, this would need to be offset by the additional scheduling value of the gross pool DAM for NESO.

Functionally, the provisions of some existing contracts would likely need to be amended to transact based on a reference price, such as the DAM price, for contracts to endure as an effective hedge between parties.

Design elements which apply to both options

Parties that are not required to, or choose not to, participate in the BM could continue to bid into the wholesale market at an aggregated level. Suppliers would be expected to bid at the Supplier BMU (GSP group) granularity.

In the current market design, not all trades have prices associated with the transaction. For example, price-taking orders and MVRNs do not necessarily have a price. The effectiveness of unit bidding would be degraded if these transactions continued without price information and may act as an incentive to take unpriced actions. Therefore, an explicit price would need to be provided for all physical trades, including those that are currently unpriced.

As we propose to retain a single energy imbalance price, the outcome of cashout under unit level participation would be identical to Trading Party (portfolio) level settlement[41].

Energy Imbalance would continue to be calculated at Energy Account level and invoiced at Trading Party level. Elexon would be responsible for aggregating unit level information to the appropriate level for settlement calculations and invoicing.

[41] I.e. imbalance volumes and charges of a long-unit within a portfolio would offset against the volume and charges of a short-unit in that same portfolio

We assume that interconnector nominations for non-coupled markets would remain separate and independent. Further, we would expect Non-Physical Traders (NPTs) to continue to arbitrage between the price of the day-ahead market and the Imbalance Price.

IMPLEMENTATION CONSIDERATIONS

Unit bidding would represent a significant change to the current market arrangements, requiring market participants to revise trading strategies and to deliver changes to proprietary systems and processes.

The implementation and ongoing operational impacts vary based on the unit bidding option. However, both options assume:

- Unit bidding will apply to all assets that participate in the BM.
- Supplier BMUs will trade at GSP group level and non-BM assets can continue to bid in the wholesale market at an aggregated level.
- The market trading deadline is re-aligned to gate closure (Section 4.1.2) and obligations are in place that require market participants to ensure unit level traded positions match FPNs (Section 4.1.3).

This section explores the expected impacts and implementation considerations from both unit bidding options.

Option 1: Physical Implementation Impacts

In Option 1, the forward market remains unchanged with market participants required to disaggregate portfolios into units at the day-ahead stage. This would require additional obligations for market participants to submit unit level traded volumes and prices at day-ahead and intraday timeframes. Under unit bidding, FPNs would be expected to match traded positions at gate closure at the latest.

Market participants would be required to update proprietary systems, processes and trading strategies to ensure volumes are allocated appropriately in unit-level accounts, data transfer timing rules are met, and message payloads are updated to include unit level data. These changes are anticipated to be a transitional critical path activity and set the pace of implementation.

Market participants with portfolios containing a diverse set of technology types may experience larger transitional and enduring impacts to effectively manage forecasting and trading. For example, accurately forecasting intermittent generation at a unit level (e.g. wind) and ensuring FPN and traded position match may require additional tools and capabilities.

Central party impacts are expected to be lower under unit bidding Option 1 when compared to Option 2. Changes to data transfer rules and higher data volumes associated with unit level submissions may impact the functional requirements of NESO, Elexon, and potentially Power Exchange systems. Unit level traded volumes would also require Elexon to aggregate volumes to energy account level for imbalance settlement purposes.

Option 2: Financial Implementation Impacts

The implementation impacts for Option 2 of unit bidding are expected to be more considerable than Option 1. Market Participants would be required to update systems and processes to ensure all physical volumes are traded through the DAM. A new central role, the Gross Pool Market Operator, would be necessary to manage the gross pool day-ahead and intraday markets.

It is anticipated that the role of Gross Pool Market Operator would be assumed by either the Power Exchanges or NESO (or multiple Power Exchanges with combined order books). Should the Power Exchanges take on this responsibility, it would likely necessitate their designation as a licensed party. Establishing the gross pool would require significant system and process development to allow for additional data feeds and notification of physical positions based on bids and offers. Careful consideration will need to be given on how best to achieve effective implementation while keeping cost down and ensuring the best service provision. This includes the context of the current GB model which has multiple Power Exchanges. This will be the subject of future exploration and discussion.

Impacts on Industry

The following is a list of transitional and enduring impacts of the reform on industry bodies as well as market participants identified in a preliminary analysis. These impacts are subject to change as decisions around policy and market design firm up. For further information on impacts please refer to Appendix 3: Impact Tables.

- Systems updates to power exchanges and market participant trading systems anticipated to ensure day-ahead and intraday trading can function at unit level. This may also include new power exchange products with unit-level prices, to allow for complex bids.
- Power exchanges may need to become licensed parties.
- Proprietary systems may need to disaggregate portfolios into units for forecasting, trading and settlement processes.
- Impacts may be higher for Market Participants with portfolios containing many assets, both during transition and on an enduring basis. This reform will likely create an increased ongoing operational effort to manage unit level forecasting and trading.
- Level of impact is expected to vary based on technology types. A higher impact is likely to effectively manage intermittent generation (e.g. wind and solar), as volumes can no longer be allocated across a portfolio.

Questions on Unit-Level Bidding

Q21. Value of unit-level granularity:

What benefits and risks do you associate with introducing unit-level bidding and nominations in the wholesale market, including the potential requirement to submit these at Day-Ahead and Intra-Day stages?

Please address and specify when referring to Option 1 or Option 2:

- How this change could support alignment between physical notifications and final traded positions.
- Impacts on transparency, market monitoring, and deterrence of inefficient, strategic behaviours.
- Potential effects on liquidity, price formation, and participant risk exposure.
- Differences between physical (Option 1) and financial (Option 2) approaches, including operational complexity and portfolio aggregation challenge (e.g., breaking down aggregated positions into individual unit bids, managing compliance across diverse assets).

Q22. Cost, proportionate granularity and implementation timelines

What implementation and ongoing costs should NESO consider associated with implementing unit level bidding? What level of unit granularity would be practical and proportionate to deliver meaningful system benefits?

Please address and specify when referring to Option 1 or Option 2:

- Implementation and ongoing costs, including IT, data, and compliance requirements associated with different unit-level approaches.
- Practicality and proportionality of different levels of granularity (the extent to which positions are broken down purely to BMU level or aggregated by GSP group), and where the balance lies between system value and implementation burden.
- Implementation timelines and key dependencies, including interactions with cross-border market coupling and the provision of ancillary services.

Quantitative section

Q23. On a scale of 1–5, how confident are you that unit-level bidding (option 1 physical) will materially enhance transparency, scheduling, and market monitoring, relative to its complexity and transition costs?

Q24. On a scale of 1–5, how confident are you that unit-level bidding (option 2 financial) will materially enhance transparency, scheduling, and market monitoring, relative to its complexity and transition costs?

Scale:
1 = Not confident
5 = Very confident

4.1.5 Shorter Settlement Period

Challenges addressed	Operability and cost challenge from increasing redispatch Distorted wholesale price signals, and incentives to exacerbate constraints
Options under consideration	• Maintain 30-min SP • 15-min SP • 5-min SP
NESO's working assumption	• 5-min SP (subject to CBA and implementation assessment)
Implementation approach	• Phased • Phase 1: Wholesale electricity market (generators, suppliers) trade at the new SP. Introduce within 30-minute profiling for Retail consumers (e.g. domestic and small business). • Phase 2: Retail consumers
NESO suggested implementation timeline	• Timeline to be defined based on feedback to the Call for Input and the Cost Benefit Analysis

Our view is that the current 30-minute SP does not provide efficient temporal signals to market participants. This creates additional redispatch actions as more intervention is required to anticipate and correct imbalances, increasing balancing costs.

Imbalance prices are calculated based on balancing actions taken by NESO. However, the price and duration of actions taken in short-periods within the current 30-minute SP do not reflect the value of energy over the whole period. This means that balancing actions in the BM can be diverse across a single SP, even if they are purely for energy reasons.

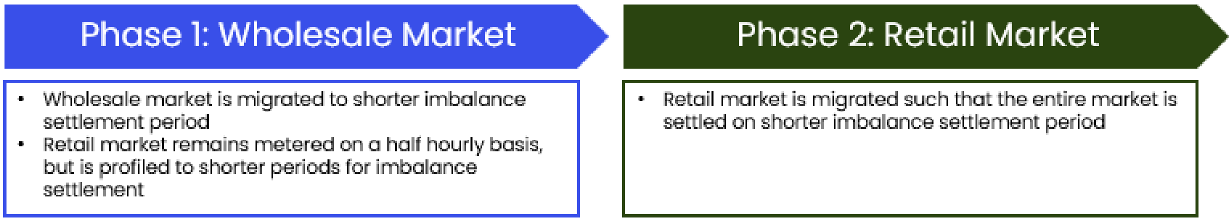
This reduces the effectiveness of the imbalance price in coordinating market participants across time, i.e. what is required for balancing the system in the first half of the current SP can be different from what is required in the second half. In a system increasingly composed of fast-acting resources and renewables, this is suppressing essential operational signals for flexibility.

Given this, our initial view is that a 5-minute SP may be the most effective enduring solution. The trade-off between the better balancing outcome (of 5 minutes) and the expected greater cost and complexity (of 5 minutes relative to 15 minutes) will be assessed through the cost benefit analysis. Moving to 5 minutes also reduces the risk of having to shorten the SP again in the future (as could be the case under 15 minutes). For the avoidance of doubt, the decision to progress with a shorter SP, and the SP length is still subject to feedback from this Call for Input, CBA and further assessment.

Initial Implementation Considerations

We recognise that reducing SP length will require a large, and potentially disruptive industry implementation programme. Our current view is that implementation would be phased, to minimise impacts where possible and to take advantage of opportunities to coordinate delivery with other relevant industry changes. The shorter SP CBA will be key to identifying the most cost-efficient delivery route.

Our initial assessment has considered implementation across two phases with a preceding detailed design period, which would ultimately transition the entire market to be settled on a shorter SP. We anticipate shorter SPs would be delivered through an industry-wide programme, that would manage the required design, build, testing, migration, and stakeholder engagement activities.



Phase 1: Wholesale Market

Phase 1 focuses on implementing a shorter SP in the wholesale electricity market while maintaining half-hourly metering and introducing within 30-minute profiling to the shorter SP for the retail market (i.e. domestic and small business consumers). Key activities in phase 1 would include delivering the full suite of central system and process updates for both the wholesale and retail market, and migrating the wholesale market. While Phase 1 would not immediately impose shorter settlement metering on domestic and small business consumers, it would initiate the required market participant system and consumer hardware updates.

Phase 2: Retail Market (e.g. domestic and small business consumers)

Phase 2 would migrate domestic and small business consumers from within 30-minute profiling to metering at the shorter SP. We anticipate that the migration would follow a similar cadence to the MHHS programme, transitioning parties based on readiness, qualification status and appetite.

We have presented the primary assumptions and activities for a phased shorter SP in Table 2.

Table 2: *Shorter Settlement Period implementation assumptions and activities*

Phase 1	Phase 2
Main Assumptions	
• Wholesale metering is already shorter settlement ready (5 and 15 minute) or with minimal adjustments (confirmation needed).	• Migration aligns with the roll out of capable metering. • First cohorts of domestic and small business consumers with capable smart meters will be moved to shorter settlement at early stage,

• The retail market (domestic and small business consumers) would be profiled to shorter SPs. • Suppliers or aggregators with capable smart meters might voluntarily opt some customer portfolios into shorter SPs ahead of the mandatory Phase 2 timeline, similarly to elective HH settlement process under MHHS. • Industry-wide implementation programme will oversee market readiness and manage testing, trials, and stakeholder engagement.	while others may temporarily remain on within 30-minute profiling. • Data collection systems are scaled to retrieve and deliver shorter settlement readings. • Elexon's Flexibility Market Asset Registration service is expected to be fully operational. • Market Facilitator will continue developing standard APIs and data portals to ensure seamless data exchange between the settlement system, DSOs, NESO, and participants. • DSO-operated markets (for congestion management or local balancing) may be updated to shorter settlement intervals so that all levels of the system operate on a consistent timeframe.
Main activities	
• Updates to central systems and processes. • Establish and implement within 30-minute profiling approach for domestic and small business consumers. • Develop plan to update forecasting, trading, risk management, and billing systems. • Industry agreement on technical standards for shorter settlement data in smart meters. • Meter operators begin the planning of retrofit or replacement of meters. • Developing plans to roll out any necessary metering hardware or firmware upgrades so that the retail market can transition in Phase 2.	• Migrate domestic and small business consumers to metering at the shorter SP. • Retail suppliers must upgrade proprietary systems (e.g. billing, settlement and cost forecasting). • DSOs can choose to align their local flexibility services and network management to the shorter settlement cadence. • Phase 2 will be executed under a detailed migration plan informed by the trials and preparations of Phase 1.

Further Considerations

The time between Gate Closure and the end of the relevant SP is referred to as the "balancing window" and is currently 90 minutes long[42]. A shorter SP could introduce a 'tighter gate closure' effect as the balancing window gets shorter, reducing to 75 minutes under a 15-minute SP, or 65 minutes under a 5-minute SP. This can result in both positive and negative impacts and requires further consideration as part of detailed design. This is shown illustratively below.

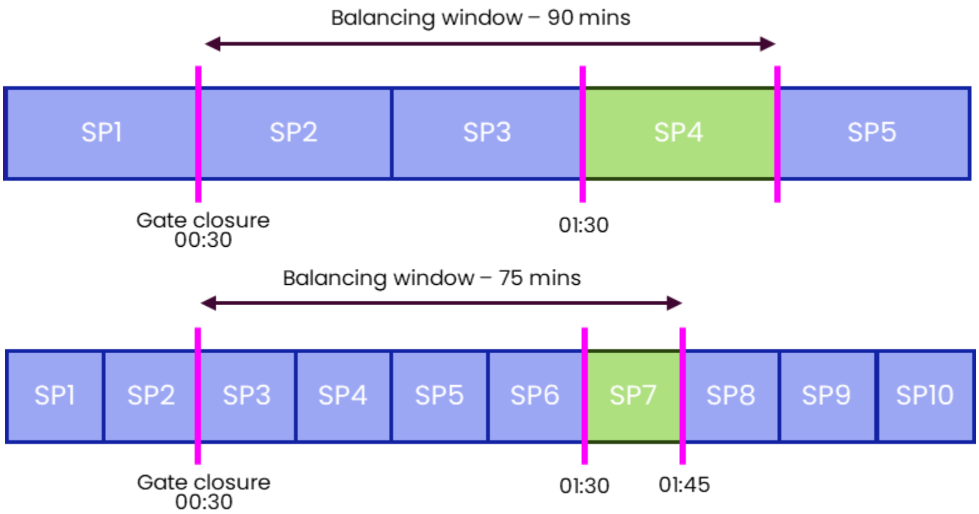


Figure 31: *Potential challenges of the balancing windows*

Potential challenges of the balancing windows getting shorter include:

1. Exacerbating intertemporal issues for assets with long Notice to Deviate from Zero (NDZ) times. The NDZ represents the time between the SO instructing a unit to move from zero and the unit actually being able to move, due to things like needing to warm up the asset from cold, or to send out control staff to perform operations.

   Many BMUs currently have an NDZ of 89 minutes, the longest possible NDZ to be just inside 90-minute window and therefore be dispatchable through the BM, although more flexible units often have shorter times.

2. NESO would have less time to take manual balancing actions. This is less likely to be an issue with projected improvements to automation and digitalisation of balancing processes.
3. A shorter balancing window could exacerbate the issue observed today where NESO actions, which have intertemporal impacts, distort the imbalance price.
4. A shorter SP would require improved control room capabilities to handle the increased volume of commercial data.

A potential mitigation is to keep the frequency of gate closures the same as today, i.e. every 30 minutes, such that the balancing window length is unchanged. This would mean multiple (shorter) SPs being closed at the same time.

[42] 60-minute Gate Closure + 30-minute Settlement Period = 90-minute "balancing window"

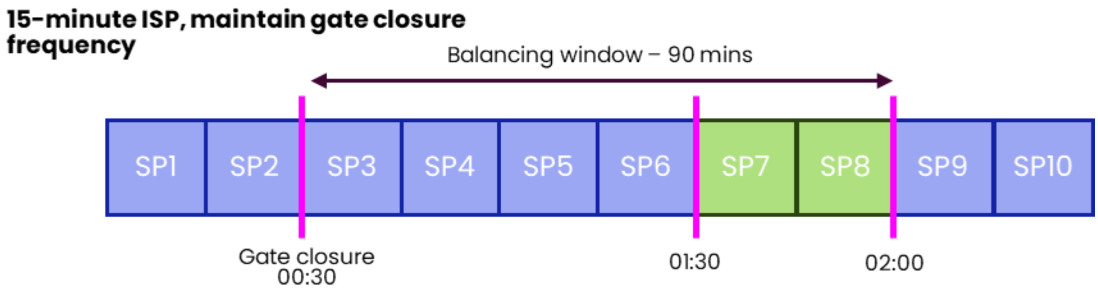


Figure 32: *Potential mitigation of the challenges of gate closure*

However, this would preclude some of the benefits of a shorter SP, preventing market participants being able to update their BM data like FPNs and bid-offer pairs as close to the start of the SPs. In the example above, it would mean that SP7 effectively had a 60-minute Gate Closure, but SP8 would have a 75-minute Gate Closure.

Furthermore, consideration on how retail arrangements interact with MHHS require further design assessment. MHHS is a key enabler in unlocking domestic flexibility, facilitating access to wholesale and balancing markets. As such, we must understand whether delivering shorter SP across two phases would negatively impact on consumer flexibility provision and may introduce the need for additional transitional arrangements.

Impacts on Industry

The following is a list of transitional and enduring impacts of the reform on industry bodies as well as market participants identified in a preliminary analysis. These impacts are subject to change as decisions around policy and market design firm up. For further information on impacts please refer to Appendix 3: Impact Tables.

- Adapt trading strategies to the new shorter SP granularity. More granular prices could mean higher volatility which might increase risk. Suppliers may need to refine their hedging and trading practices to manage intra-hour price risk.
- Power exchanges to introduce new tradable products that align to shorter SPs
- Trading platform providers will need to upgrade their systems to handle more granular auctions or continuous trading resolution.
- Updates to central balancing and settlement systems to receive and action higher data volumes. Any interactions with MHHS will be key to understand here.
- Potential requirement for additional system operation capabilities and tools
- Suppliers will need to handle a large increase in data from smart meters. IT systems for forecasting demand, validating meter data, and calculating customer bills or cost-of-energy will require enhancement.
- A key transitional challenge arises where metering standards or hardware cannot yet support the new SP granularity. Providers with legacy meters or low-resolution telemetry may be unable to verify delivery, risking reduced market access, settlement disputes, or reliance on temporary estimation/baselining methods.

- Cost and logistics of installing sub-30-minute metering.
- Time-of-use tariffs and other dynamic pricing offerings to consumers could become more precise. Suppliers might develop new products that pass through these granular prices to customers or reward customers for shifting load at the new SP. While this creates opportunities for innovation, it also means billing systems and customer data handling must be upgraded.

Questions on Shorter Settlement Period

Q25. Temporal efficiency and system outcomes:

How effective would shorter SPs (e.g. 5 or 15 minutes) be in addressing temporal inefficiency, imbalance volatility, and the use of fast-acting flexibility?

Please consider:

- Whether settlement granularity should move in step with other market timelines (e.g. Gate Closure, trading deadlines).
- Operational and commercial impacts on your organisation.
- Interactions with imbalance pricing and balancing actions.
- Which market participant cohorts would benefit most from shorter SPs, and how could this inform staged implementation?

Q26. Cost, deliverability and implementation timelines for shorter SPs

What are the principal implementation and ongoing cost drivers in delivering shorter settlement periods (5 or 15 minutes), and how can these be mitigated to ensure a smooth transition?

Please comment on, identifying any differences between 5 and 15 minutes:

- Implementation and ongoing cost drivers, including system upgrades, metering changes, data and forecasting requirements, and impacts on internal operational processes.
- Practical and logistical challenges of metering upgrades or installations, and supplier system readiness.
- Implementation timelines and feasibility of phased vs. single step migration, including key dependencies (e.g. digitalisation progress, readiness of trading and settlement systems, metering upgrades).
- Transitional arrangements—such as shadow settlement or staged go live—that could support a stable migration.

Quantitative section

Q27. On a scale of 1–5, how confident are you that shorter SPs (e.g. 5 or 15 minutes) will materially improve temporal efficiency and use of fast-acting flexibility, given current and planned system, data, and metering capabilities?

Scale:
1 = Not confident, 5 = Very confident

4.2 Cost Benefit Analysis

The CBA is intended to assess the economic impact of the proposed balancing reform package. While the reforms themselves relate to balancing & settlement, their impact may play out, indirectly, across a range of electricity markets, including the retail market, wholesale market, BM, ancillary services markets, as well as in relation to imbalance settlement. We therefore intend to capture the impacts of the balancing reform package across all relevant markets (potentially subject to a materiality threshold).

The CBA of the balancing reform package will evaluate the costs and benefits at a system level and to affected parties in the context of the future electricity system development.[43] The specific timeframe for the CBA will be defined in due course, but NESO expects that this will likely cover the period from around 2027 to 2050.

NESO's CBA approach is expected to involve a mix of quantitative and qualitative assessment of the impact of the balancing reforms, driven by data availability and proportionality principles.

NESO expects to rely on a mixture of historical data, fundamental power market modelling, as well as qualitative and quantitative input from stakeholders.

- NESO will document the historical data used for the CBA, and clarify whether this is public or non-public information, as well as where it has been obtained (e.g. from NESO's own databases, Elexon and/or, if available, power exchanges).
- NESO will combine the historical data with forward-looking electricity system modelling that captures the dynamics of these impacts and the development of the electricity system in GB to determine the relative scale of different costs and benefits under different assumptions.
- In relation to stakeholder input, NESO welcomes stakeholder input to support the collection of quantitative data on the impact on system costs of implementing and operating under the balancing reforms. NESO also invites stakeholders to provide qualitative information on the impact of the reforms on stakeholder incentives and behaviours over both short (i.e., scheduling, operational) and long (i.e., planning, investment) timescales. Following this Call for Input, NESO may issue formal data requests to support the CBA.

The CBA is expected to deploy a multi-criteria assessment of the factors described above and provide a recommendation, on the balancing reforms package.

Counterfactual

There are aspects of the RNP and of other market design elements that are likely to change over the coming years, though these remain uncertain at this stage. Given the uncertain

[43] For the forward-looking assessment, we anticipate that there will be a need to define a specific scenario, or several scenarios, for which the CBA will be performed. This will be clarified as part of the CBA itself and could include scenarios such as the UK Government's Clean Power 2030 plan, and/or Future Energy Scenarios.

nature of the context in which the Balancing reforms package would be potentially introduced, it is important to clearly define the counterfactual for the purposes of the CBA.

While the specific counterfactual will be determined alongside the CBA methodology, NESO's intention is to use a counterfactual that reflects, based on the information available at the time of performing the CBA, the market design that is currently in place together with other ongoing reforms that have a high level of certainty regarding implementation details and timeline.

Structure of the CBA

The primary aim is to develop a transparent and robust methodology that aligns with the strategic objectives and policy context of the reforms.

This methodology will be scenario-based and include sensitivity testing to ensure that the analysis is resilient to uncertainties and varying assumptions; for example, by exploring how phased versus immediate implementation of different threshold changes might affect system costs, market access, and operational efficiency, alongside other metrics to be assessed.

Additionally, the analysis will consider regulatory scenario testing, for instance with attention paid to the impact of ongoing and future code modifications. Such code changes may interact with or alter the effectiveness of the RNP reforms, so it will be important to identify which modifications are likely to have a significant effect and to assess them accordingly.

The CBA will be expected to quantify both the costs and benefits of each individual reform as well as the combined reform package. This includes assessing metrics including, but not limited to, system costs/savings, impacts on consumer bills, distributional effects across different market participants, and gains in operational efficiency.

A key requirement is that the analysis should not only evaluate each reform in isolation but also consider their collective impact, capturing any interdependencies or cumulative effects. This approach is intended to provide a nuanced understanding of how each reform contributes to the overall objectives, both on its own and as part of a broader package.

Furthermore, to understand the full transitional and enduring impacts of the proposed RNP Balancing reforms, NESO will be working alongside Ofgem, DESNZ, and the industry to complete a detailed impact assessment. This will assess the full range of direct implementation, ongoing operational, and indirect whole system impacts. This is an essential component required to support the CBA and, ultimately, a recommendation on the RNP Balancing reforms in 2026.

Industry feedback to this Call for Input and through our RNP engagement will be critical to ensure that we effectively capture the full range of impacts. We have presented our initial thinking on the expected impacts in Appendix 3.

4.3 Implementation Roadmap

In addition to informing the overall RNP decision, the CBA and Impact Assessment will be used to develop an implementation roadmap. We anticipate that the Balancing reforms will form part of a broader RNP implementation programme that will be delivered across a series of distinct phases.

Adopting a phased implementation approach will allow changes to be implemented when they are ready, ensuring that industry and consumer benefits are realised as soon as possible. We aim to develop the industry implementation roadmap in collaboration with Ofgem, DESNZ, and the industry to ensure it considers existing change pipelines and impacts are proportionate. Where practical, we will seek opportunities to enhance impacted processes (e.g. BM registration), to minimise transitional impacts and ensure enduring arrangements are optimal.

Questions on Cost–Benefit Analysis and Evaluation Framework:

Q28. To what extent do you agree with the proposed CBA methodology and evaluation framework, and are there additional factors NESO should consider?

Please focus your response on:

- Whether you agree with the overall CBA approach and methodology, and whether any important factors are missing.
- Expected operational or market behaviour impacts (e.g. forecasting, trading strategies, operational planning) that should be reflected in the CBA.
- Key risks or uncertainties (e.g. liquidity impacts, forecasting uncertainty, operational risks) that should be captured in sensitivity analysis.
- How your organisation typically estimates implementation costs (e.g. CAPEX vs OPEX, system upgrade cycles), and any practical challenges in providing robust cost estimates for the balancing reform package.
- Any distributional or competition impacts that should be included to distinguish system wide benefits from simple cost transfers.
- Which post implementation metrics or indicators would be most meaningful to assess success.

Questions on Implementation Roadmap and Assessment

Q29. To what extent do you agree with the proposed approach to developing the implementation roadmap, and what practical considerations should NESO take into account?

In your response, please comment on:

- Whether you agree with the overall approach to sequencing and phasing reforms, and whether any important elements are missing.
- Practical insights on implementation timelines and organisational readiness, including internal lead times, required system changes, and interactions with other industry programmes.
- Key dependencies and risks NESO should account for (e.g. digitalisation constraints, system readiness, regulatory interactions, potential bottlenecks across the current market change pipeline).
- Transitional arrangements that may ease implementation, such as phased migration, shadow operation, or alternative access routes for smaller participants.
- Any evidence or experience (e.g. data availability, expected operational impacts, lessons from previous programmes) that would materially improve the practicality or proportionality of the roadmap.

5 Dispatch Reform

5.1 Case for further reform

In the previous chapters, we highlighted that the proposed Balancing Reforms are expected to provide some significant benefits in the form of increased supply and competition for balancing the system, a clear handover of balancing responsibility between market participants and NESO, and market rules that facilitate fair, efficient and transparent market.

However, even with the proposed balancing and wider RNP reforms, the fundamental misalignment between the national wholesale price and locational system needs will remain.

In the context of constraints, a key element of assessing whether to reinforce electricity networks is the trade-off between the up-front cost of network investment versus the ongoing cost of managing constraints. If the cost of the reinforcement is lower than the cost of the constraint, then the reinforcement makes economic sense. If it is higher, it does not.

With clean-power resources typically located much further away from large centres of demand than the previous fossil fuel generation fleet, network reinforcements to reduce constraints are correspondingly longer and so more expensive. This in turn results in a shift of the tipping-point where the cost of ongoing constraint management outweighs the one-off cost of network reinforcement, requiring higher constraint costs before reinforcement are justified. As such, even with significant network reinforcement, constraint volumes may remain high.

As a result, significant NESO intervention could still be needed to unwind self-dispatch market positions to maintain system security; this could be significantly challenging, inefficient, and expensive, in turn having a direct impact on consumer bills.

While the proposed RNP reforms should help with managing the effects of this, we believe that there is more that could be done to meet the overall RNP objectives and particularly the operability and cost challenge from high levels of redispatch.

The rest of this chapter will outline the status of dispatch reform in RNP, the potential scope and examples from other countries, and the interaction with the other RNP reforms.

5.2 Status of Dispatch Reform in RNP

Reforms to the wider dispatch arrangements have previously been explored under the REMA programme. NESO's Scheduling & Dispatch options[44] work outlined three broad types of dispatch arrangement used in electricity systems around the world: self-dispatch, central dispatch, and hybrid dispatch.

As part of the 2024 REMA Autumn update, DESNZ adopted a minded-to position not to take forward central dispatch.

[44] NESO Scheduling and Dispatch – Options Webinar

However, given the challenges outlined above and previously in this Call for Input, NESO, DESNZ and Ofgem will continue to explore a range of other dispatch reform options with a view to improving system operability and reducing costs for consumers.

To be clear, any reform to dispatch arrangements must satisfactorily address a number of key requirements, including delivering benefits for consumers, ensuring future system operability, maintaining investor confidence, and ensuring compatibility with the Government's legal obligations and international agreements.

We are seeking views from stakeholders on the case for Dispatch Reform in this Call for Input.

5.3 Types of dispatch arrangements

The following figure gives an overview of the key features and principles of different dispatch arrangements found in other jurisdictions around the world, as outlined in our previous Scheduling & Dispatch options work:

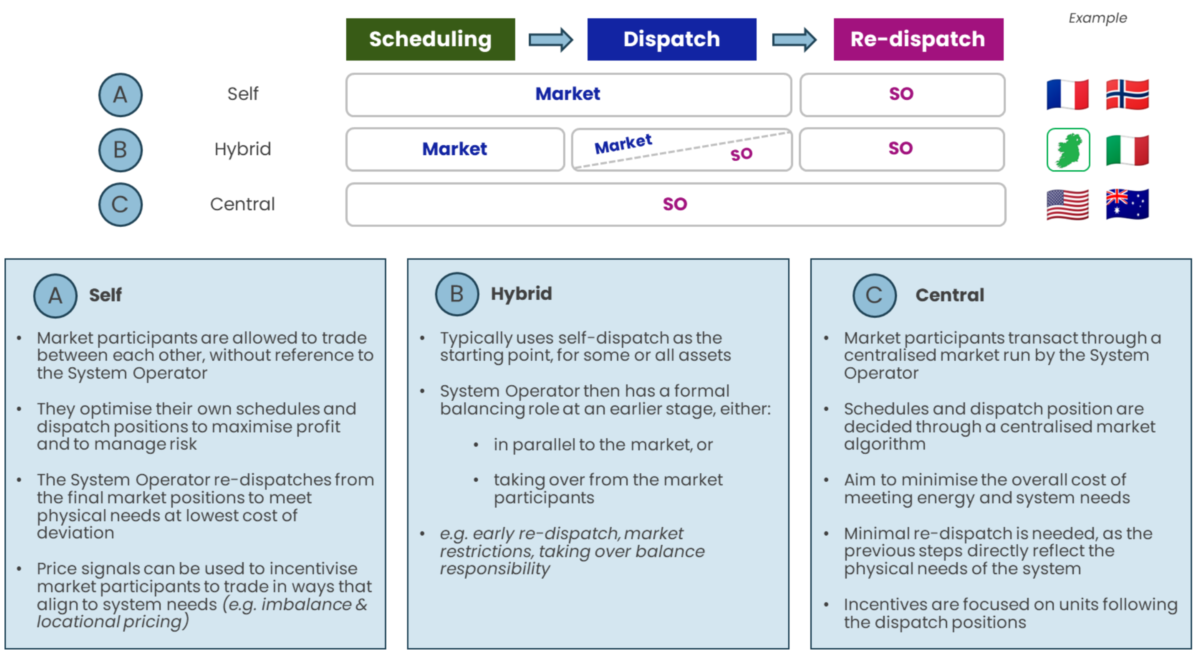


Figure 33: *Three broad types of dispatch arrangement*

The main differences between dispatch arrangements are around how the scheduling and dispatch positions of units are set, and how any misalignment between those positions and the physical needs of the system are resolved. The greater the misalignment, the more redispatch will be needed. In the context of the four challenges identified in Section 2, this especially affects the **operability and cost challenge from increasing redispatch.**

Alignment between dispatch positions and system needs:

The three main factors influencing the level of alignment between dispatch positions and system needs are:

- **Level of congestion on the system:**
  For example, if there are few constraints on the network, then dispatch positions can flow easily across the system and there is likely to be good alignment. Conversely, with many constraints dispatch cannot flow easily, often leading to poor alignment.
- **Incentives on market participants:**
  If there are price incentives to align the dispatch position with the system needs, such as short SPs (when) or locational prices (where), then there is more likely to be good alignment. Without these, there is more scope for poor alignment.
- **Dispatch arrangements:**
  Different dispatch arrangements lead to different approaches for aligning dispatch positions and system needs. The following diagrams aim to illustrate at a high-level how the different approaches typically work.

Self-dispatch

The market trades based on the relevant incentives, but largely independently of system needs. The SO then redispatches to resolve any misalignment between the dispatch positions and system needs.

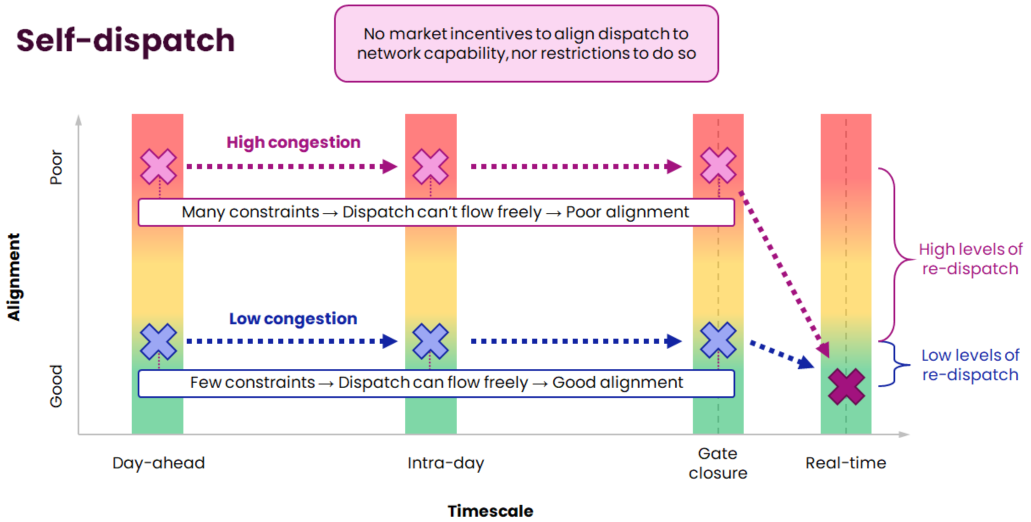


Figure 34: *Illustration of how self-dispatch arrangements typically approach the alignment between dispatch positions and system needs*

Central dispatch

Positions are derived from a centrally operated market which considers the prices and capabilities of assets alongside the needs of the system. Therefore, the initial dispatch can differ somewhat compared with a self-dispatch regime, especially on a congested network. This means there is typically much less need for redispatch, as the dispatch is always aligned to the best view of system needs at the time. However, the scheduling is still subject to factors like forecast errors and price changes, which can still lead to changes in the level of alignment over time.

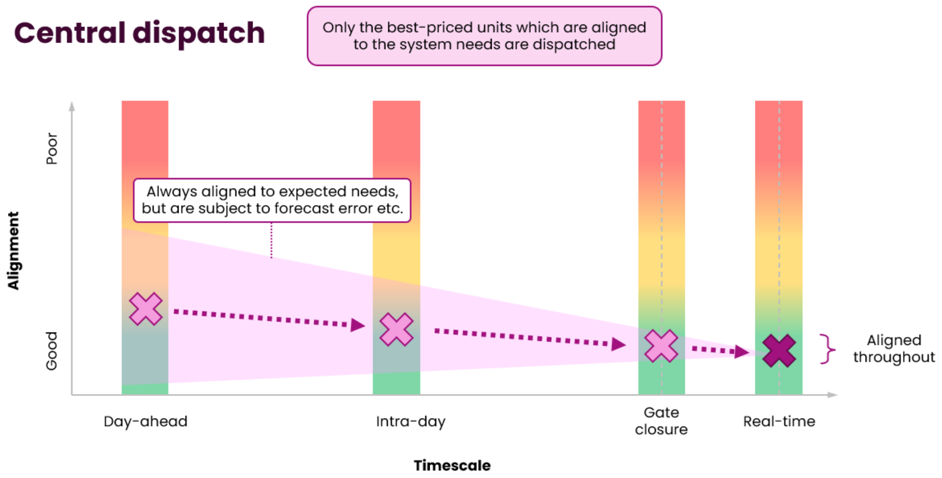


Figure 35: *Illustration of how central-dispatch arrangements typically approach the alignment between dispatch positions and system needs*

HYBRID DISPATCH

This typically uses self-dispatch as the starting point, for some or all assets. The SO then has a formal balancing role at an earlier stage, whether in parallel to the market or taking over from the market participants; this could be in the form of things like early redispatch, applying market trading restrictions on particular units or areas, or fully taking over balance responsibility:

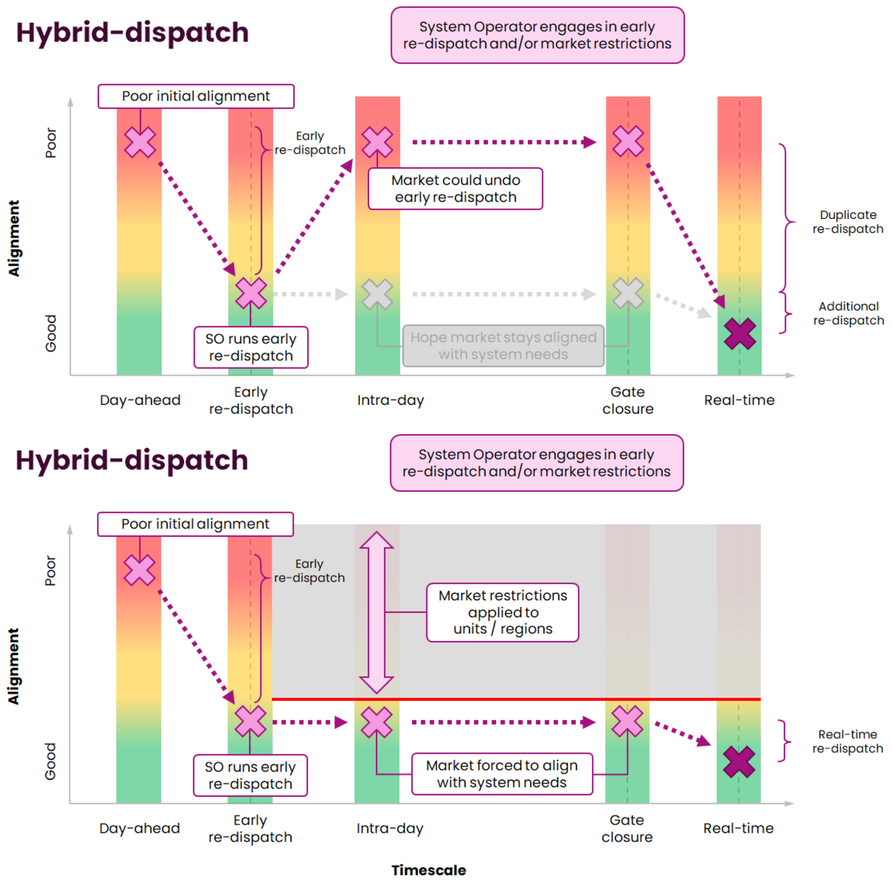


Figure 36: *Illustration of how hybrid-dispatch arrangements typically approach the alignment between dispatch positions and system needs*

Current context:

Self-dispatch

It is the combination of these three elements (level of congestion, market incentives, and dispatch arrangements) that affects the alignment: there can be good alignment between dispatch and system needs and low redispatch under national pricing self-dispatch arrangements, but only if the level of congestion is low.

These were the assumptions that underpinned the NETA for England and Wales, and the BETTA when Scotland was incorporated into the arrangements.

However, with current self-dispatch arrangements, significant redispatch is highly likely to continue be required in the future due to a rapidly evolving technology mix and uncertainty around increasing levels of system constraints.

Central dispatch

As noted above, DESNZ' adopted a minded-to position not to take forward Central Dispatch in the 2024 REMA Autumn update.

The update acknowledged the potential benefits it could bring for managing high volumes of congestion cost effectively, especially for enabling co-optimisation of energy and ancillary services, but also cited concerns around deliverability, investor confidence, and value for money.

Hybrid dispatch

There are many examples of what we would call "hybrid-dispatch" regimes in other countries, especially in Europe. These are outlined in the box below to give a flavour of the sorts of approaches that are used elsewhere.

We would like to understand and explore the range of options, opportunities and challenges associated with such hybrid approaches if they were applied in GB.

Box 12: European approaches to hybrid-dispatch

Day-ahead schedules

The typical case in Europe (within the IEM) is that the day-ahead schedule for market participants is achieved through a self-dispatch market coupling algorithm.

In most countries the day-ahead auction builds on existing forward physical positions, but in some countries, such as Spain or Ireland and Northern Ireland, this is the first opportunity to achieve a physical position; all forward trading is financial.

In some countries the SO has ability to set the schedule of some assets; for example, in Italy the new MACSE scheme is a tolling agreement that means battery assets provide their flexibility to other market participants and/or to the SO.

Early redispatch

The SO then assesses the need for any redispatch to align the day-ahead schedule with the physical capability of the system. Where redispatch is needed, this is done through, for example, constraint management markets or early redispatch (akin to doing a first run of the BM shortly after day-ahead).

In some countries this redispatch is without compensation, such as those with non-firm access (e.g. Spain). In others there are examples of redispatch that is cost-based (e.g. Germany) or market-based[45] (e.g. The Netherlands).

Each of these approaches has different benefits and drawbacks, around revenue certainty, market signals, opportunities for gaming, and the reflectiveness of estimating costs.

Market restrictions

While early redispatch might solve the needs based on the day-ahead market schedules, there is then a risk that the market might undo the early redispatch.

For example, if a SO took bids at day-ahead in one region to resolve an export constraint, there is a risk that the market then schedules more generation in that region during the intraday market. This could partly or wholly undo the early redispatch, meaning more redispatch and higher balancing costs overall.

For this reason, many countries apply some form of restriction on what can be traded in the wholesale market after the early redispatch: this applies to not just the units which have been redispatched, but also to other units in the same area.

This is the approach taken in the Netherlands, where the SO might dispatch down demand to manage import constraints, and then place restriction on other demand assets in the same area buying more power within-day.

In Italy, which operates a more centralised version of a hybrid-dispatch regime, the SO calculates "feasibility intervals" which assign each unit an envelope of flexibility up and down from their day-ahead position which they can trade within-day.

While these restrictions can be important for making the early redispatch effective, they can impact on the flexibility and opportunities of market participants within day, especially those such as batteries and renewables which use the intraday to manage forecast errors or to achieve arbitrage between evolving market prices and within-day scarcity.

However, in the absence of restrictions, such subsequent wholesale market trades might not necessarily be welfare-enhancing overall, as they too would need to be redispatched closer to real-time at a cost to the consumer.

5.4 Interaction with the other RNP Reforms

We foresee that dispatch reform could have the potential to complement and enhance each of the RNP pillars:

[45] "Cost-based" means that market participants can only reflect the cost of redispatch, not a profit margin, and is generally a more regulated approach. "Market-based" means that market participants are free to choose the price they submit, but are still subject to competition in a way that acts as a restraint on prices

SSEP levers

The SSEP and associated siting levers are expected to deliver a step-change improvement in the investment signals for where to site assets.

However, having assets located in the right place is only one part of the picture; assets then also need the right operational signals and dispatch arrangements to be used economically and efficiently. Also, as described at the start of the chapter, the tipping-point of the economic trade-off between ongoing constraints costs and one-off network reinforcement is shifting as low-carbon resources are located further from demand.

These challenges exist in both the Constraint Management and the Balancing pillars of RNP, which deal with the operational signals for assets.

Dispatch Reform could help to address these challenges, by creating a more holistic approach to using assets across both the wholesale market and the balancing market than is possible under the current self-dispatch arrangements.

Constraint management

There are three key elements of the Constraint Management pillar where Dispatch Reform could have significant potential to deliver improvements. These are:

- Pre-Gate Closure balancing
- Storage asset management
- Interconnectors flows

Pre-Gate Closure and constraint management

NESO's role was designed to be a residual balancer, taking actions to align the position the market has traded ahead of time with the needs of the system. Gate Closure should typically represent the handover point between the two activities. However, pre-Gate Closure actions are sometimes necessary and/or more economic, due to the nature of the assets needing to be re-dispatched. NESO being more active pre-Gate Closure, such as more trading or establishing new pre-Gate Closure ancillary services markets, may undermine the handover and needs to be carefully considered.

In a similar way to supporting the SSEP and associated levers, Dispatch Reform could lead to better pre-Gate Closure constraint management by creating a more holistic approach to utilising assets across the wholesale market and balancing market, building on the constraint management proposals.

Storage assets

Efficient use of storage can provide opportunities for reducing constraints costs, if the assets are given signals to respond in a system-supportive way. Under a national pricing framework, wholesale market prices do not always reflect local constraints, which can create inefficient behaviour from all asset types.

Rather than relying on incremental redispatch after Gate Closure, Dispatch Reform could offer the opportunity to ensure more efficient use of all assets, including storage, by better co-ordinating between the constraints of the network and the overall production and consumption of energy on the system across all time periods.

Dispatch reform could provide for more effective competition between technologies, e.g., the trade-off between time-limited BESS and longer-duration but potentially more expensive technologies such as gas-fired generation, allowing them to be accounted for in a comprehensive and integrated way.

Interconnectors

Interconnector re-dispatch is often used to balance and secure the system, whether because they are the lowest cost option, or in some cases because they are the only option. They are and will continue to be an important part of the capacity mix and flexibility capability of GB, and an essential part of a clean power system.

DESNZ, Ofgem, and NESO are already assessing in the wider RNP package what more can be done to improve the alignment of flow and system need of interconnectors relative to network constraints. Additionally, working closely with DESNZ and Ofgem, we are continuing to engage with connected SOs to develop bilateral measures to improve cross-border trading, balancing and coordination.

We want to explore whether Dispatch Reform could offer further opportunity to better align and manage interconnector flows and redispatch, by co-ordinating dispatch and redispatch at an earlier stage. This applies not just for interconnectors, but across all assets and network constraints. As always, this would need to be in conjunction and coordination with other SOs and connected countries, and would also depend on the overall framework for cross-border trading and re-dispatch.

Balancing reforms

As discussed in Section 3 on balancing reform, the package addresses the challenges to a varying extent. We see it being particularly effective around:

- Insufficient visibility and access to balancing resources
- Overlap between the wholesale market and balancing
- Distorted wholesale price signals, and incentives to exacerbate constraints

Dispatch reform would look to complement the balancing reforms and provide wider benefits across all of the challenges, with a particular focus on improving the:

- Operability and cost challenge from increasing redispatch

For example, while the combination of a shorter SP, lower BM threshold and introducing unit bidding would improve the efficiency of resource allocation and facilitate more secure operation of the system, significant levels of redispatch could still be required in real-time under the current self-dispatch arrangements.

Dispatch reform could help to address this challenge by creating earlier alignment between the market position and the needs of the system, reducing the need for redispatch close to real time.

Similarly, a shorter SP should help with creating more efficient temporal signals for market participants to respond to, but they will not address the locational signals where assets should dispatch or how, in particular, two-way assets could be optimised over time to support operational system needs.

Dispatch arrangements that aid in creating these signals for the market could help address some of the key underlying reasons for redispatch today.

Dispatch reform could also further support and enhance the other challenges that the balancing reforms address, by creating a more coherent market with clearly defined roles for market participants and NESO.

QUESTIONS ON DISPATCH REFORM

Q30. Objectives and Design Principles

What should be the primary objectives and guiding principles for investigating any future dispatch reform in the GB electricity market?
Please address:

- How dispatch reform could improve system efficiency, transparency, and cost-effectiveness.
- The role of market signals versus centralised instructions in achieving these objectives.
- Key considerations for maintaining competition and liquidity under new dispatch arrangements.

Q31. Market and Operational Impacts

What impacts—positive or negative—could dispatch reform have on market participants and system operation?
Please comment on:

- Dynamics and interactions between market participants and system operation, as illustrated in the diagrams.
- Effects on trading strategies, risk management, and portfolio optimisation.
- Implications for different participant types (generators, suppliers, aggregators, storage, DSOs, interconnectors).
- Potential interactions with other reforms (e.g. unit bidding, shorter SPs).
- Implementation and ongoing cost implications, including system upgrades, process changes, and operational readiness for participants.

Q32. Implementation Pathways and Risks

What implementation pathways and risk mitigations should NESO consider for dispatch reform?
Please address:

- Feasibility of phased or incremental approaches.
- Data, system, and governance requirements.
- Transitional arrangements to minimise disruption and ensure proportionality.

- Potential implementation timelines and associated costs, including required system changes and operational readiness.

QUANTITATIVE SECTION

Q33. On a scale of 1–5, do you agree that further dispatch reform on top of the proposed balancing reforms will be needed to meet the future operability and redispatch cost challenges described in Section 2.3 and Section 5?

Scale:
1 = Strongly disagree
5 = Strongly agree

6 Next Steps

Thank you for taking the time to read this Call for Input and for engaging with the proposed reforms. Your consideration of these issues is greatly appreciated, and your expertise and perspectives are essential to shaping an effective and enduring market framework that supports a secure, efficient, and low-carbon electricity system.

We encourage all stakeholders—across all market roles and sectors—to provide feedback. We recognise that this Call for Input covers a wide-ranging and complex set of reforms, and we welcome insights that reflect operational experience, system-level considerations, and the diverse challenges faced across the industry.

Your responses will directly inform the next stage of design, the CBA, and the development of a robust implementation pathway for the balancing and dispatch reforms. In addition, we invite stakeholder suggestions on other reform options that have not been considered, and which could help address the balancing and dispatch reform challenges.

Following the submission of feedback, we will review all responses and incorporate them into our assessment process. We look forward to continuing this collaboration as we refine the proposals and work toward delivering a more efficient and resilient electricity market for the future.

Please provide all feedback via the response proforma by 5:00 p.m. on Tuesday 14th April 2026.

Responses may be shared with DESNZ and Ofgem as our partners in the RNP programme. Responses may also be shared publicly. If any part of your response is confidential and should not be published, please indicate this in your response.

After the publication of the Call for Input our next steps are as follows:

1. Call for Input Webinar in March 2026
2. Review Call for Input responses, your answers will feed directly into the cost-benefit analysis, impact assessments and implementation planning.
3. Provide recommendations to support decision making process in the second half of 2026.
4. Alongside the work above we will continue to assess the options for dispatch reform considering the feedback from this Call for Input.

Opportunities for engagement after the Call for Input will be provided to ensure the CBA, impact assessments and implementation planning can be comprehensively assessed. More information on this will be shared on our RNP programme webpage.

For any questions or clarifications, please contact **box.market.strategy@neso.energy**.

7 Appendices

Appendix 1: Full list of Call for Input questions

Reform principles

Q1. Reform principles and inherent trade-offs

Do the stated balancing and dispatch reform principles identified in Section 2.2 provide a coherent and achievable framework under a national pricing, self-dispatch market design?

Please consider:

- Whether the principles conflict (e.g. transparency vs liquidity, clear handover vs flexibility).
- Which principles should take priority, or where trade-offs arise. Please provide your prioritisation of principles.
- Whether any additional principles, or changes to existing principles are required to ensure reforms support the future system needs.

Q2. On a scale of 1–5, how confident are you that the balancing and dispatch reform principles set out in Section 2.2 (efficient operational signals, clear handover of balancing responsibility, secure and efficient operation of the system) are a suitable framework for reform under a national pricing, self-dispatch market design?

Scale:
1 = Not confident
5 = Very confident

Challenges to Address

Q3. System challenges and causal drivers

To what extent do you believe each of the challenges in defined in Section 2.3 contribute to current and future redispatch volumes and costs?

In your response, please comment on:

- Which challenges you consider structural drivers versus secondary symptoms
- Whether any challenges are over- or under-emphasised relative to the others
- Evidence from your operations, experience, knowledge of the market, and empirical or anecdotal evidence that supports alternative interpretations of redispatch growth.

Q4. On a scale of 1–5, how impactful do you consider the operability and cost challenge from increasing redispatch to be for the GB system over the next 5–10 years?

Q5. On a scale of 1–5, how impactful do you consider the challenge of insufficient visibility of and access to balancing resources (particularly distributed and flexible assets) to be for secure and efficient system operation?

Q6. On a scale of 1–5, how impactful do you consider the challenge of misalignment and overlap between the wholesale market and balancing (including overlapping timeframes and conflicting signals) to be for market functioning and NESO's role as residual balancer?

Q7. On a scale of 1–5, how impactful do you consider the challenge of distorted wholesale price signals and incentives to exacerbate system constraints (including opportunities for strategic positioning around congestion) to be for investment and consumer outcomes?

Scale:
1 = Low impact
5 = High impact

Effectiveness of the Balancing Reform Package

Q8. Impact on redispatch volumes, actions, costs:

Do you agree with the interactions and dependencies in the reform package defined in Section 3 to manage redispatch volumes, actions, and costs, do you see any gaps?

In your response, please comment on:

- The volume, timing, cost, and predictability of redispatch actions.
- NESO's ability to act as a residual balancer, rather than a de facto central scheduler?
- Interactions with other reforms, such as P462 or other RNP reforms, that could amplify or diminish their impact on redispatch.

Please distinguish between expected impacts in the early transition period and the enduring state.

Q9. Market behaviour and strategic response:

How do you expect market participants' behaviour to change in response to the balancing reform package defined in Section 3?

Please reflect on:

- Changes in trading, scheduling, and risk-management strategies
- Potential new optimisation, arbitrage, or strategic behaviours that could emerge
- Which design features are most important to mitigate unintended outcomes

Q10. Distributional and competitive impacts:

What distributional impacts do you expect across different participant types and technologies as a result of the full balancing reform package implementation defined in Section 3?

Please consider:

- Impacts on generators (by technology), suppliers, storage, aggregators, DSOs, interconnectors, and consumers.
- How this change would affect your business operations (operational practices, trading strategies, and risk management).
- Whether impacts are temporary (transition-related) or structural for the market operation.

- Where targeted transitional measures may be justified, and where they could create longer-term distortions

Q11. On a scale of 1–5, how confident are you that the balancing reform package as described in Section 3 will materially improve operational efficiency and support NESO in managing the four challenges identified in Section 2.3?

Scale:
1 = Not confident
5 = Very confident

Reform 1 Lower Mandatory Balancing Mechanism Threshold

Q12. Cost, benefits and implementation impacts

What implementation and ongoing costs should NESO consider associated with lowering the mandatory BM threshold reform, and what operational benefits or opportunities do you expect?

Please comment on:

- Implementation timelines and associated costs, including feasibility of phased rollout, retrospective application and target BM threshold.
- Which asset types or business models face the most material implementation and operational cost impacts, and where the reform may generate net benefits across your portfolio.
- How the reform would change your cost exposure when providing or using flexibility services
- Interactions with DSO flexibility arrangements or flexible connection agreements that may increase or decrease costs or benefits.

Q13. Proportionality and implementation

What barriers or challenges might smaller participants encounter with lowering the BM threshold? What steps could be taken to manage impacts, while ensuring the stated objectives of enhanced visibility and access are achieved?

Please comment on:

- Proportionality of compliance requirements.
- The role of aggregators or alternative access routes.
- Transitional arrangements/incentives to support parties in meeting BM obligations.
- Any specific risks to competition or market access that we should consider.

Q14. On a scale of 1–5, how confident are you that lowering the mandatory BM participation threshold will significantly improve visibility and access to balancing resources, while remaining proportionate in terms of costs and obligations?

Scale:
1 = Not confident
5 = Very confident

Reform 2 Aligning Market Trading Deadline with Gate Closure

Q15. Risk allocation and market functioning

How would aligning the market trading deadline with gate closure reallocate forecast, imbalance, and operational risk between market participants and NESO?

Please consider:

- Impacts on trading liquidity and intraday risk management.
- Current use of post-gate-closure trading.
- Effects on different technologies and business models.
- Whether the reform strengthens or weakens the clarity of balancing responsibility.

Q16. Implementation timelines, costs and transition considerations

What implementation and ongoing costs should NESO consider associated with aligning the market trading deadline with gate closure?

Please comment on:

- Implementation timelines and costs of adapting trading systems and internal processes to an earlier deadline.
- Cross border or contractual factors that may increase cost or extend implementation timelines.
- Any ongoing cost implications of the change.

Q17. On a scale of 1–5, how confident are you that aligning the market trading deadline with Gate Closure will improve clarity of balancing responsibility and reduce inefficient overlap between market trading and NESO balancing actions?

Scale:
1 = Not confident
5 = Very confident

Reform 3 Physical Notifications Matching Traded Positions

Q18. Costs, benefits and implementation feasibility of FPN to match traded positions

What implementation and ongoing costs should NESO consider associated with implementing FPNs to match traded positions?

Please comment on:

- Implementation and ongoing costs, including system changes, forecasting processes, and compliance requirements.
- Differences in cost and implementation timelines between portfolio level and unit level approaches.

- How differing technologies within a portfolio may affect the complexity, cost, and practicality of implementing the reform.

Q19. Risks, tolerances and exemptions

What risks or unintended consequences could arise from the different scenarios proposed for FPN to match traded positions under portfolio bidding or unit bidding, and how should tolerances or exemptions be designed?

Please comment on:

- Technology-specific and contract structure differences.
- Potential gaming or risk-shifting behaviours.
- Governance and enforcement considerations during transition.
- Whether obligations should differ between aggregated portfolios and disaggregated unit-level positions.

Q20. On a scale of 1–5, how confident are you that requiring FPN to match traded positions will improve forecasting accuracy, transparency, and NESO's operational confidence, without creating disproportionate implementation or compliance risks?

Scale:
1 = Not confident
5 = Very confident

Reform 4 Unit Level Bidding

Q21. Value of unit-level granularity:

What benefits and risks do you associate with introducing unit-level bidding and nominations in the wholesale market, including the potential requirement to submit these at Day-Ahead and Intra-Day stages?

Please address and specify when referring to Option 1 or Option 2:

- How this change could support alignment between physical notifications and final traded positions.
- Impacts on visibility pre-gate closure, market monitoring, and deterrence of inefficient, strategic behaviours.
- Potential effects on liquidity, price formation, and participant risk exposure.
- Differences between physical (Option 1) and financial (Option 2) approaches, including operational complexity and portfolio aggregation challenge (e.g. breaking down aggregated positions into individual unit bids, managing compliance across diverse assets).

Q22. Cost, proportionate granularity and implementation timelines

What implementation and ongoing costs should NESO consider associated with implementing unit level bidding? What level of unit granularity would be practical and proportionate to deliver meaningful system benefits?

Please address and specify when referring to Option 1 or Option 2:

- Implementation and ongoing costs, including IT, data, and compliance requirements associated with different unit-level approaches.
- Practicality and proportionality of different levels of granularity (the extent to which positions are broken down purely to BMU level or aggregated by GSP group), and where the balance lies between system value and implementation burden.
- Implementation timelines and key dependencies, including interactions with cross-border market coupling and the provision of ancillary services.

Q23. On a scale of 1–5, how confident are you that unit-level bidding (option 1 physical) will materially enhance transparency, scheduling, and market monitoring, relative to its complexity and transition costs?

Q24. On a scale of 1–5, how confident are you that unit-level bidding (option 2 financial) will materially enhance transparency, scheduling, and market monitoring, relative to its complexity and transition costs?

Scale:
1 = Not confident
5 = Very confident

Reform 5 Shorter Settlement Period

Q25. Temporal efficiency and system outcomes:

How effective would shorter SPs (e.g., 5 or 15 minutes) be in addressing temporal inefficiency, imbalance volatility, and the use of fast-acting flexibility?

Please consider:

- Whether settlement granularity should move in step with other market timelines (e.g. gate closure, trading deadlines)
- Operational and commercial impacts on your organisation
- Interactions with imbalance pricing and balancing actions
- Which market participant cohorts would benefit most from shorter SPs, and how could this inform staged implementation?

Q26. Cost, deliverability and implementation timelines for shorter SPs

What are the principal implementation and ongoing cost drivers in delivering shorter settlement periods (5 or 15 minutes), and how can these be mitigated to ensure a smooth transition?

Please comment on, identifying any differences between 5 and 15 minutes:

- Implementation and ongoing cost drivers, including system upgrades, metering changes, data and forecasting requirements, and impacts on internal operational processes.
- Practical and logistical challenges of metering upgrades or installations, and supplier system readiness.

- Implementation timelines and feasibility of phased vs. single step migration, including key dependencies (e.g. digitalisation progress, readiness of trading and settlement systems, metering upgrades).
- Transitional arrangements—such as shadow settlement or staged go live—that could support a stable migration.

Q27. On a scale of 1–5, how confident are you that shorter SPs (e.g. 5 or 15 minutes) will materially improve temporal efficiency and use of fast-acting flexibility, given current and planned system, data, and metering capabilities?

Scale:
1 = Not confident
5 = Very confident

Reform Package Cost–Benefit Analysis and Evaluation Framework

Q28. To what extent do you agree with the proposed CBA methodology and evaluation framework, and are there additional factors NESO should consider?

Please focus your response on:

- Whether you agree with the overall CBA approach and methodology, and whether any important factors are missing.
- Expected operational or market behaviour impacts (e.g. forecasting, trading strategies, operational planning) that should be reflected in the CBA.
- Key risks or uncertainties (e.g., liquidity impacts, forecasting uncertainty, operational risks) that should be captured in sensitivity analysis.
- How your organisation typically estimates implementation costs (e.g. CAPEX vs OPEX, system upgrade cycles), and any practical challenges in providing robust cost estimates for the balancing reform package.
- Any distributional or competition impacts that should be included to distinguish system wide benefits from simple cost transfers.
- Which post implementation metrics or indicators would be most meaningful to assess success.

Reform Package Implementation Roadmap

Q29. To what extent do you agree with the proposed approach to developing the implementation roadmap, and what practical considerations should NESO take into account?

In your response, please comment on:

- Whether you agree with the overall approach to sequencing and phasing reforms, and whether any important elements are missing.
- Practical insights on implementation timelines and organisational readiness, including internal lead times, required system changes, and interactions with other industry programmes.

- Key dependencies and risks NESO should account for (e.g. digitalisation constraints, system readiness, regulatory interactions, potential bottlenecks across the current market change pipeline).
- Transitional arrangements that may ease implementation, such as phased migration, shadow operation, or alternative access routes for smaller participants.
- Any evidence or experience (e.g. data availability, expected operational impacts, lessons from previous programmes) that would materially improve the practicality or proportionality of the roadmap.

Dispatch Reform

For all the following questions refer to Section 5.

Q30. Objectives and Design Principles

What should be the primary objectives and guiding principles for investigating any future dispatch reform in the GB electricity market?

Please address:

- How dispatch reform could improve system efficiency, transparency, and cost-effectiveness.
- The role of market signals versus centralised instructions in achieving these objectives.
- Key considerations for maintaining competition and liquidity under new dispatch arrangements.

Q31. Market and Operational Impacts

What impacts—positive or negative—could dispatch reform have on market participants and system operation?

Please comment on:

- Dynamics and interactions between market participants and system operation, as illustrated in the diagrams.
- Effects on trading strategies, risk management, and portfolio optimisation.
- Implications for different participant types (generators, suppliers, aggregators, storage, DSOs, interconnectors).
- Potential interactions with other reforms (e.g., unit bidding, shorter SPs).
- Implementation and ongoing cost implications, including system upgrades, process changes, and operational readiness for participants.

Q32. Implementation Pathways and Risks

What implementation pathways and risk mitigations should NESO consider for dispatch reform?

Please address:

- Feasibility of phased or incremental approaches.

- Data, system, and governance requirements.
- Transitional arrangements to minimise disruption and ensure proportionality.
- Potential implementation timelines and associated costs, including required system changes and operational readiness.

Q33. On a scale of 1–5, do you agree that further dispatch reform on top of the proposed balancing reforms will be needed to meet the future operability and redispatch cost challenges described in Section 2.3 and Section 5?

Scale:
1 = Strongly disagree
5 = Strongly agree

Appendix 2: Previously Considered Options

Dual imbalance price

GB has had a single imbalance price since the Electricity Balancing Significant Code Review, where the imbalance price faced by market participants depends only on whether the system as a whole is short or long. A dual imbalance price would mean that the price paid by market participants for imbalances would depend both on whether the system was short or long, and whether the party themselves were short or long. A dual imbalance price provides a stronger incentive to self-balance ahead of time by removing the 'reward' for being in the opposite direction to the system length and therefore would decrease the incentive on parties to engage in NIV chasing.

While a dual imbalance price would reduce the incentive to NIV chase, one of the imbalance prices will not be aligned with the cost to NESO of balancing the system, and could therefore send the wrong market signals. It can also create additional imbalance risk for market participants, as short and long positions on assets within a portfolio would no-longer offset each other.

We believe that combination of the other proposed balancing reforms is sufficient to address the impact of NIV chasing, and in addition provide much wider consumer and system benefits. Hence, there is not enough justification to implement a dual imbalance price on top of this, given that it could also reduce the cost reflectively of imbalance and undermine the formation of reference prices.

Scarcity price adder

Scarcity pricing is informally defined as the process by which short-term energy prices rise above the marginal cost of the marginal unit, i.e. the last unit in the merit order to produce power in the market. Scarcity pricing typically occurs under stressed system conditions.

The proposal was to introduce a scarcity price adder through Operational Reserve Demand Curves (ORDCs) to real-time balancing market prices when the system is tight. This is to signal value for flexible assets to be available for NESO in real-time.

Reserve scarcity pricing could bring benefits but is complex to design and implement; there is scope to continue to consider outside the RNP Programme

There is a strong economic rationale for a disciplined implementation of Reserve Scarcity Pricing in GB; however, the proposal considered was to introduce a scarcity price adder on top of the imbalance price to incentivise greater self-balancing, which would be (i) less effective under a shorter SP which is inherently more volatile (ii) has the potential for detrimental unintended consequences. Furthermore, any implementation of Reserve Scarcity Pricing would be complex to implement.

Pay-as-clear Balancing Mechanism

Under current arrangements, the BM operates as a pay-as-bid (PAB) market. This means that if a BM action is taken then the balancing party will receive the price they submitted.

This means that different assets may be paid different prices than each other for energy delivered in the same period, if they submitted different prices. Moving to a pay-as-clear (PAC) BM would change this so that all parties were paid the same prices of the most expensive offer accepted for the same period.

The original market design under NETA concluded that *"When markets are broadly competitive, [pay-as-clear] and pay-as-bid produce similar results, but that when market power is evident, pay-as-bid can have advantages."*[46]

There are potential advantages of being able to use PAC, but also some necessary conditions:

Necessary conditions	Potential advantages of PAC
Homogenous product: all actions are on the same basis and for the same reason	Incentives for participants to bid at short-run marginal cost (SRMC)
	Easier for capacity to bid and participate – particularly smaller players
Sufficient competition: if providers bid above marginal price they must risk not being accepted	More efficient dispatch
Perfect information of the market available to all market participants	A clear reference price acts as an incentive on balancing service providers

The level of congestion in the national price regime means that many actions in the BM are taken for constraint management reasons, sometimes for both constraint and energy reasons, and sometime just for energy reasons. This means that Bid-Offer Acceptances (BOAs) do not form a "homogenous product", as they are used for different reasons at different times and in different places.

Also, the most recent assessment of whether the BM should remain PAB found that *"for most the time, there is evidence of a moderately or highly concentrated market, where the majority of market share of the bid and offers accepted for energy balancing is being provided by a small number of providers"*, and that *"the HHI data challenges the assumption that the Balancing Mechanism is an unconcentrated market, and at least at certain periods there may not be sufficient competition (especially given the heterogeneity of the product) to say there is sufficient competition"*.[47]

While a move to a shorter SP would improve homogeneity of balancing actions, we do not believe that this would be sufficient by itself to meet the condition of a homogenous product given the potential for enduring levels of congestion on the system. An argument which has previously been made in favour of changing to PAC is that it would incentivise dispatchable

[46] The New Electricity Trading Arrangements, Ofgem/DTI Conclusions Document, October 1999
[47] BM and STOR PAB derogation, 2019

resources into the BM. However, we feel this would be done more effectively by lowering the mandatory BM threshold as proposed.

Change to Gate Closure time

NESO previously considered changing the timing of Gate Closure as part of the REMA programme. Given the amount of redispatch NESO is currently doing, and is expected to do in the future, extending Gate Closure would give NESO more time to take more effective dispatch actions. This was ruled out because of the increased imbalance risk to intermittent renewables, which could lead to market participants increasing risk premiums in their bids and offers.

There has also been a suggestion that the time between Gate Closure should be shortened. Given the large, and increasing, amount of redispatch actions that NESO needs to take, it is NESO's view that it would not be compatible with effective redispatch to shorten the period between Gate Closure and real time.

Appendix 3: Impact Tables

The impacts discussed in this appendix are an initial assessment and are subject to change based on the feedback to this Call for Input, the Cost Benefit Analysis, and the Implementation Impact Assessment. We welcome your view on the details presented below via the questions in the main body of the Call for Input, your feedback will be essential in us refining and developing our detailed impact assessment.

Lower mandatory BM participation threshold

Who	Expected Impact

Central Parties	• Increased volumes of registrations into the BM during transition and on an enduring basis. This is expected to require a review of NESO and Elexon processes, such as registration and BM participation, to ensure obligations are fit for purpose and accelerate the need for process optimisation and automation.
	• NESO, DSOs, and the Market Facilitator may be required to accelerate the design of the system operation coordination model, such that the process, system, and regulatory requirements are defined in line with the RNP implementation roadmap. This is expected to include, but is not limited to:
	    o whether BM participation requires migration from Supplier Volume Allocation (SVA) to Central Volume Allocation (CVA) arrangements for all assets that are 1 MW or greater;
	    o if BM participation via a VLP is a valid entry route and, if yes, the entry conditions;
	    o management of complex sites, including onsite generation; and
	    o DSO and NESO operational coordination (primacy), stacking, and data sharing rules.
	• Expected transitional impact to central parties to manage the migration of connected assets and assets within the connection queue into the BM, including coordinating the revision of existing connection applications and offers.
	• Greater visibility is expected to support earlier identification of emerging imbalances, leading to a reduction in balancing costs (though not imbalance volumes).
	• Anticipated transitional impact to NESO, Elexon, ElectraLink, the Energy Networks Association (ENA) and OFGEM to progress the required code modifications. Final code impacts will be subject to the final design, yet are expected to impact the Grid Code, CUSC, Distribution Code, Distribution Connection and Use of System Agreement (DCUSA), and the BSC.

Who	Expected Impact
	• Operational process and data sharing impacts to NESO and DSOs, to support greater coordination of the transmission and distribution systems. NESO may require access to real-time data and network models to ensure that dispatch instructions respect local system conditions and are not unwound by Automatic Network Management (ANM) systems. • Potential need for NESO, or DSOs, to coordinate the retrofitting of metering and communication equipment for existing DERs to support the integration of distribution and transmission SCADA systems. • Increased geographical and locational diversity of available balancing resources, allowing for more efficient energy balancing and network management actions. • Potential transfer of liquidity from the intraday market into the BM between T-60 and T-0. • Higher participation of DERs in the BM may lead to a reduction in DSO flexibility market liquidity. Further assessment of DSO market impacts is required during detailed design and in the definition of enduring stacking rules. • Greater access to DER and distribution network data may unlock improvement opportunities across NESO's business functions, processes and systems. For example, additional data could be used by network planning, outage planning, market monitoring, to inform market reform, and system operations for the purpose of modelling, forecasting, and operational planning. • Functional changes to NESO balancing and forecasting systems likely required to manage higher data volumes and support more efficient dispatch decisions. Higher unit volumes may also introduce requirements for additional control room process optimisation and automation • Likely impact to NESO market monitoring and reporting processes to ensure transparency of BMU utilisation. • Increased emphasis on NESO's dispatch and transparency programme ensuring effective use and transparent reporting of utilisation of new BMUs, such that migration benefits are achieved.
Market Participants	• Assets impacted by the lower mandatory BM threshold will need to undertake registration, demonstrating compliance with BM participation obligations. Once registered as a BMU, there will be ongoing operational requirements to comply with BM rules, such as submitting Bids and Offers, and PNs. • Potentially higher impact to assets between 10 and 1 MW and assets that were connected prior to EREC G99 (April 2019) to meet BM operational requirements, which may introduce requirements to retrofit metering equipment.

Who	Expected Impact
	• Potential impact where design allows for assets to meet mandatory threshold obligations by participating through an aggregator/VLP. This may be a key entry route for smaller assets (e.g. 1 MW), which may prefer to outsource operational management. • Potential impact to manage BM participation on behalf of customers (e.g. customers with on-site generation and export tariffs). • Disincentive to NIV chase through the reduction of the volume of flexibility that is active outside the BM. • Transitional impact to projects within the connection queue that may be subject to changes in connection agreements and/or additional obligations to participate in the BM. • Lowering mandatory BM thresholds may impact CfD generators by triggering Qualifying Change in Law provisions. This requires further assessment as part of detailed design. • Additional revenue opportunity through BM participation.

Align Market Trading Deadline to Gate Closure

Who	Expected Impact
Central Parties	• Potential to result in increased energy balancing actions as the market is unable to correct its imbalance position between T-60 and T-0. However, expected to reduce flagged (network management) actions taken by NESO in the BM • BSC code changes expected to align market trading deadline to gate closure. • System & process impacts to Energy Contract Volume Aggregation Agent (ECVAA) expected, to ensure ECVAA only accepts ECVNs & MVRNs by Gate Closure. • Changes expected to BSC Subsidiary Documents: ECVAA Service Description and ECVAA User Requirements Specification. • Potential updates required to BSC assurance processes that monitor compliance of ECVN & MVRN submissions. • Power Exchanges may be required to update their platforms to adhere with the new trading deadline. Impact expected to be limited to the Continuous Intraday Market.
Market Participants	• BSC Trading Parties may need to update their systems and processes to cease any trading activity post Gate Closure and submit their ECVNs & MVRNs by Gate Closure in line with updated BSC obligations. • Market Participants may be required to update their trading strategies and potentially enhance forecasting capabilities to better manage their imbalance position by Gate Closure. • Removal of near real-time trading opportunities for market participants may increase their imbalance risk. This is particularly relevant for renewable generators, which may deviate from their FPNs due to less accurate forecasts being available at Gate Closure compared to real-time. • Potential impact to near real-time flexibility, requiring improved coordination between flexibility markets and the BM. • Expected to reduce incentives for decentralised balancing/NIV chasing.

FPNs to match traded positions

Who	Expected Impact
Central Parties	• Providing NESO visibility of the aggregated market traded position is expected to introduce additional process, system, and data transfer requirements to Elexon and NESO, subject to the final design. This assumes that Elexon would calculate the aggregated traded volume (from ECVN and MVRN) and transfer it to NESO at gate closure. • Further assessment is required to define the aggregated traded volume calculation methodology and may result in additional process, or data changes. This may include introducing additional requirements to capture volumes allocated within vertically integrated companies, or traded in NESO ancillary services and DSO flexibility markets. • NESO may need to update its system operation processes, strategies, and tooling to integrate and optimise the use of the aggregated traded position into the control room. • Introducing an obligation for FPNs to match traded position may introduce additional market monitoring, assurance, and compliance requirements, which may differ under portfolio, or unit bidding market arrangements. • FPNs to match traded position rules may need to acknowledge the relative complexities of accurately forecasting the physical positions different technology types to ensure obligations are proportionate. For example, dispatchable bidirectional units (e.g. batteries) may be subject to a higher accuracy threshold than intermittent renewable generation (e.g. wind and solar PV) • Power exchanges may be required to progress changes to the Energy Contract Volumes data flow structures, such that notifications to the ECVAA are compliant with any new requirements (e.g. to enable matching calculations).
Market Participants	• Market participants may not be able to adjust their physical position as easily, as they will also be required to change their trading position • Market participants may be required to progress updates to processes and systems associated with sending contracted energy volumes (ECVNs and MVRN) to ensure that Elexon has the necessary data to calculate the aggregated traded position. This may include changes to the timings of data transfers, progressing changes to

Who	Expected Impact
	data structure, and sending additional data flows to capture volumes allocated across vertically integrated accounts. • Under unit bidding arrangements, market participants may need to update proprietary processes, systems, and strategies to ensure that physical and financial positions match. • Consideration needed of how to accommodate generation forecast changes due to weather (e.g. wind and solar PV). • Market Participants may be required to enhance near-real time forecasting capabilities to ensure PN accuracy and manage imbalance risk. • Aggregated BMUs, such as those managed by VLPs, or Supplier BMUs may be exposed to a greater non-compliance risk due to the relative complexity of accurately forecasting aggregated units. • Potential reduction in provision of flexibility from the wholesale market near-real time, given the incentive for the market to fix its position at gate closure.

Unit bidding

<table>
<tr><th>Who</th><th>Expected Impact</th></tr>
<tr><td>Central Parties</td><td>Both options
Unit bidding may increase the implementation complexity of other RNP balancing reforms. In particular, due to the significant increase to in data volumes related to trading activity.
Code modifications are expected to reflect unit-level data submissions.
Impacts may be seen where account changes are required for additional collateral obligations.
Systems updates to power exchanges and market participant trading systems anticipated to ensure day-ahead and intraday trading can function at unit level. This may also include new power exchange products with unit-level prices, to allow for complex bids.
Enhancements to market monitoring processes and tools may be required to utilise locational trading data and identify potential breaches in REMIT. Potential requirement for a central party to take on additional market monitoring responsibilities
Option 1: Physical
Potential requirement for new functionality to aggregate unit-level ECVNs to Energy Account level for the purposes of imbalance settlement.
This reform may require increased monitoring from transition to ongoing operations to assess wholesale market impacts such as liquidity.
Monitoring may also be required for price reporting in the wholesale market.
Subject to design decisions for the FPN matching Traded Position reform, NESO may be required to receive aggregated ECVN volumes ahead of SPs.
Option 2: Financial
Establishing the gross pool would require significant system and process development whoever took on the role to allow for additional data feeds and notification of physical positions based on bids and offers
Further impact could be seen in the event that Power Exchanges become the Gross Pool market operator e.g. they may be required to become a licensed party.</td></tr>
</table>

<table>
<tr><th>Who</th><th>Expected Impact</th></tr>
<tr><td>Market Participants</td><td>Both
Market participants will likely need to progress changes to systems, processes and strategies to nominate units and manage unit bidding at Day-Ahead stage.
Proprietary systems may need to disaggregate portfolios into units for forecasting, trading and settlement processes.
Impacts may be higher for Market Participants with portfolios containing many assets, both during transition and on an enduring basis. This reform will likely create an increased ongoing operational effort to manage unit level forecasting and trading.
Level of impact is expected to vary based on technology types. A higher impact is likely to effectively manage intermittent generation (e.g. wind and solar), as volumes can no longer be allocated across a portfolio.
Option 1
Vertically Integrated Utilities would be required to disaggregate their portfolios.
Minimal impact expected to Supplier BMUs, where they remain at a portfolio level by GSP group.
Option 2
Trading functions and strategies must be updated as a part of this reform to account for PNs sent to the Gross pool market operator.
Impacts are expected to working capital for participants who trade via OTC or those who are vertically integrated.
Outstanding decision on required solution for Non-Physical Traders to arbitrage between the Day Ahead and imbalance prices.</td></tr>
</table>

Shorter Settlement Period

Who	Expected Impact
Central Parties	• NESO may need to adjust its scheduling, forecasting, and control room processes to operate under a shorter SP. • The reform is expected to shift some balancing activity from balancing actions into the wholesale market itself. This could reduce the volume of actions NESO needs to take in the BM, potentially lowering balancing costs and giving NESO a clearer real-time picture of the system. At an operational level NESO may require additional automation and optimisation capabilities to manage high data volumes and undertake more frequent, granular balancing actions. • Elexon's systems would need to handle shorter SP metered data, profile remaining half-hourly data to the new SP and then calculate imbalance prices and charges according to the new period. These increased data volumes may require significant modifications to settlement systems, requiring investment in system capacity, data storage, and processing performance. • BSC processes and calculations (e.g. credit cover, imbalance price calculations, SVA, market index data, etc.) would have to be reviewed and potentially modified for a shorter SP. • Governance and code documentation would need updates in all places that currently reference 30-minute SP definitions. Broader code changes may be required depending on design decisions (e.g. whether to maintain the balancing window as 90 minutes) • Currently, Power exchanges in GB in their day-ahead auctions use hourly products, and intraday markets typically offer half-hour blocks. If the imbalance SPs shorten there could be the need for shorter products. • Market Coupling and Cross-Border Trading arrangements may need to be reviewed. • NESO and Elexon could align to establish and maintaining consistent data schemas, timestamps, publication intervals, and access standards across the industry. Clear data standards would minimise integration costs and support a smooth shift to a shorter SP. • NESO and Elexon should work to align market interfaces to support shorter SP, offer data access and assure quality to support trading and real-time optimisation. Interoperability requirements and performance standards to reduce fragmentation of digital infrastructure should be ensured, with the objective of guarantee participation across NESO, DSOs, and power exchanges markets.

Who	Expected Impact
	• Electricity Market Reform Settlement (EMRS) may need functional updates to ingest and process metered data from Elexon's central systems at the new granularity. Additionally, validation, reconciliation & credit control logic may require adapting. • SP could affect the Intermittent Market Reference Price (IMRP), which is currently calculated from hourly day-ahead prices. shorter SP requires a decision on whether Low Carbon Contracts Company (LCCC) should adopt the new SP or continue using hourly aggregation. Baseload Market Reference Price (BMRP) is not expected to be impacted, as it is based on forward seasonal contracts. • Supplier demand volumes will be recorded at higher granularity, and Elexon/EMRS may need to decide whether to use these values directly or aggregate them for CfD billing cycles. For the CM, shorter SP will improve the precision of stress event detection and performance measurement.
Market Participants	• Adapt trading strategies to a shorter SP price granularity, more granular prices could mean higher volatility which might increase risk. Suppliers may need to refine their hedging and trading practices to manage intra-hour price risk, potentially using new risk management products or incurring additional risk premium. • Suppliers will need to handle a large increase in data from smart meters. IT systems for forecasting demand, validating meter data, and calculating customer bills or cost-of-energy will require enhancement. Suppliers might also have to renegotiate some contracts (such as fixed price/fixed shape wholesale contracts or Power Purchase Agreements with generators) if those were predicated on 30-minute prices. • A shorter SP may reward generators that can ramp quickly or respond on short notice. Fast-response generators could capture sharp prices spikes that would otherwise be averaged out over 30 minutes. Conversely, generators with slower ramp times or inflexible output may find it harder to take advantage of brief price peaks, potentially affecting their revenue patterns. Overall, the reform is expected to better reflect the true value of energy at each interval, which encourages efficient generation scheduling and investment in flexibility. • For variable generators, shorter SP means that forecast errors are settled more frequently. This could reduce the accumulation of imbalance if forecasts can be updated in the intraday markets. It may lower imbalance costs for renewables that have good short-term forecasting or enable them to trade out positions closer to real time. On the other hand, forecasting at a 5-, or 15-minute resolution is more challenging than forecasting 30-minute resolution – generators might need improved forecasting tools or intraday trading capabilities to manage this.

Who	Expected Impact
	Generators with storage or other flexibility on-site will likely benefit by smoothing their output or timing injections to match high-price intervals. • shorter SP enables batteries, DSR assets, Virtual Power Plants (VPPs) and VLPs to monetise individual short-term price spikes and optimise intra-hour dispatch more precisely than under 30-minute settlement. • More granular price signals should increase opportunities to earn energy-market revenues alongside ancillary services. Flexible portfolios may rebalance their capacity between energy and ancillary markets, responding dynamically to whichever market delivers the highest value. • One possible impact of a shorter SP is diluted liquidity. Market participants may find it challenging to actively trade in smaller intervals, which could result in periods with low liquidity or reliance on the BM to resolve imbalances. Exchanges will need to consider how to maintain efficient price discovery. On the other hand, more granular markets can improve price discovery for flexibility and reveal scarcity value more precisely. • Trading platform providers will need to upgrade their systems to handle more granular auctions or continuous trading resolution. Trading screen interfaces and APIs might also require updates. • A key transitional challenge arises where metering standards or hardware cannot yet support 5-minute or 15-minute measurement. Providers with legacy meters or low-resolution telemetry may be unable to verify delivery, risking reduced market access, settlement disputes, or reliance on temporary estimation/baselining methods. Upgrades will be required for some DSR and small-scale DER portfolios to ensure shorter SP compliant data and avoid being disadvantaged during the transition. • Review bilateral contracts or agreements based on 30-minute prices or volumes. A shift to 5-minute or 15-minute settlement could require contractual adjustments. They may also need upgrades to trading systems to handle more frequent bids/offers if intraday markets align with 5-minute or 15-minute periods. • Traders managing a portfolio (also applies for suppliers) will want to fine-tune positions closer to real time. Intraday market activity may increase, if liquidity in intraday products is low, traders might rely on the BM or pay imbalance charges for very short fluctuations. Efficient trading strategies will require connecting real-time operational data with market trades quickly. • With a shorter SP, time-of-use tariffs and other dynamic pricing offerings to consumers could become more precise. Suppliers might develop new products that pass through these granular prices to customers or reward

Who	Expected Impact
	customers for shifting load at 5-minute intervals. While this creates opportunities for innovation, it also means billing systems and customer data handling must be upgraded. • Large consumers on pass-through contracts (where they pay the half-hourly wholesale price or imbalance cost) will see more granular cost signals. This can be an opportunity, those who can shift or reduce load at times of high shorter prices, more so than under a 30-minute averaged price. However, consumers will need the systems and willingness to respond on very short notice, which might require automation or new energy management strategies. • Industry will need to assess whether existing meters and data loggers can record and transmit data at shorter intervals. If not, firmware upgrades or replacements might be necessary. Some meters can record at 15-minute intervals for certain programs, but 5-minute resolution may not be universally supported yet. Data providers will need to ensure that meter reading schedules and storage can handle the reads needed. Storage capacity is a concern. Some metering data systems may need significant expansion to store and archive 5-minute or 15-minute data for the required retention periods. • The Data Communications infrastructure and data collection systems may face a large increase in data traffic and storage. Profiling of non-half-hourly data will have to shift to 5-minute or 15-minute granularity. Data quality processes (estimation of missing data, validation) must be adapted to the new interval; for example, filling in a few missing 5-min or 15-min intervals vs a half-hour block. • shorter SPs may affect existing CM and CfD regulations and Terms & Conditions. This requires further assessment as part of detailed design activities.

Appendix 4: List of abbreviations

Abbreviation	Description
ANM	Active Network Management
BESS	Battery Energy Storage System
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
BMRP	Baseload Market Reference Price
BOA	Bid-Offer Acceptance
BSC	Balancing and Settlement Code
CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CfD	Contracts for Difference
CM	Capacity Market
CUSC	Connection and Use of System Code
CVA	Central Volume Allocation
DAM	Day-Ahead Market
DCUSA	Distribution Connection and Use of System Agreement
DESNZ	Department for Energy Security and Net Zero
DER	Distributed Energy Resources
DM	Dynamic Moderation
DMH	Dynamic Moderation High
DML	Dynamic Moderation Low
DNO	Distribution Network Operator
DR	Dynamic Regulation
DRH	Dynamic Regulation High
DRL	Dynamic Regulation Low
DSO	Distribution System Operator
DUKES	Digest of UK Energy Statistics
ECVAA	Energy Contract Volume Aggregation Agent
ECVN	Energy Contract Volume Notification
EMRS	Electricity Market Reform Settlement
ENA	Energy Networks Association
EREC G99	Engineering Recommendation G99
FPN	Final Physical Notification
GB	Great Britain
GSP	Grid Supply Point
ID	Intraday Market
IMRP	Intermittent Market Reference Price
LCCC	Low Carbon Contracts Company
MTU	Market Time Unit
MVRN	Metered Volume Reallocation Notification
NESO	National Energy System Operator
NETA	New Electricity Trading Arrangements

NIV	Net Imbalance Volume
NPT	Non-Physical Trader
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas and Electricity Markets
OTC	Over-the-Counter
PAB	Pay-As-Bid
PAC	Pay-As-Clear
PN	Physical Notification
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Sources
RNP	Reformed National Pricing
SDAC	Single Day Ahead Coupling
SIDC	Single Intraday Coupling
SSEP	Strategic Spatial Energy Plan
SO	System Operator
SO-SO	System Operator-to-System Operator Trading
SP	Settlement Period
SVA	Supplier Volume Allocation
TNUoS	Transmission Network Use of System (charges)
TSO	Transmission System Operator
VLP	Virtual Lead Party
VPP	Virtual Power Plant

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