Enhanced National electricity market design for Great Britain

Public Summary Report

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Key Messages

1. An enhanced national market design could be delivered with more certainty of achieving benefits than a zonal market, with less risk of delay. Within an enhanced national market, changes could be made to the treatment of interconnectors, small-scale and storage assets which would yield material benefits with limited downside risk. The zonal alternative has a wider range of outcomes, with benefits that are possibly higher but also more uncertain, with a high potential for significant downside risk (see Exhibit 1.2).
2. Any improvements to interconnector arrangements would require negotiation with neighbouring TSOs and potentially also the EU for both enhanced national and zonal market designs; a zonal market should not be seen as a route to avoiding the need for negotiation. For an enhanced national market, we believe that significant gains could be achieved bilaterally (without wider EU negotiations) by expanding existing arrangements for intraday countertrading. Further gains could be achieved with innovations to secure countertrade volumes earlier than is currently possible, although these are more likely to require EU-level negotiation (see pages 19 and 28).
3. The potential welfare gains from improved arrangements for small-scale and storage assets in the enhanced national designs are smaller but more easily achieved than those for interconnectors (see page 35). Some additional benefit could be achievable depending on how far flexible demand can be optimised in the Balancing Mechanism.
4. Other areas of reform (e.g. reformed access rights for storage assets, constraint management markets) could provide some further operational efficiency gains as part of an enhanced national market, although these have not been quantified. Some of these ideas are already being progressed by NESO and others.
5. The potential welfare benefit from a possible move to a zonal market (£3.3 billion, NPV 2030-2050 in our Zonal case) is relatively small (less than 1% of consumer bills over the same period). In practice, the benefits of the Zonal case are likely to be lower than modelled and possibly significantly outweighed (delivering net costs rather than benefits) by one or more of the following:
   i) increases in cost of capital for new renewable investment arising from exposure to zonal prices and volume risk;
   ii) delays to the introduction of zonal pricing (a 2-year delay from 2030 to 2032 would reduce the potential welfare benefit in the Zonal case by £0.8 billion);
   iii) a zonal market that is less efficient than modelled as a result of imperfect foresight of transmission constraints day-ahead, the timing of interactions with interconnected markets in the event market coupling is not achieved, and any impacts of reduced liquidity;
   iv) any compensation arrangements conceded to the EU as the result of the introduction of a zonal market (a significant share of the welfare benefit to GB in the Zonal case is the result of welfare transfers from interconnected markets);
   v) implementation costs; and
   vi) ongoing operational costs for more complicated trading arrangements, including higher costs and risks for suppliers in trading and hedging customer supplies.

Executive Summary

Under the REMA process, a range of major reform options is still under consideration. Many of the more radical reform options have now been ruled out; zonal pricing remains on the table alongside various elements of an enhanced national design[1]. Previous work by AFRY[2] concluded that zonal pricing could yield small but material efficiency gains. However, the benefits of zonal pricing are very sensitive to the level of network build, with all studies to date showing that increasing network build significantly reduces the impact. Moving to a zonal market would come at the cost of significant disruption, and with the risk that increased volatility would raise the cost of capital for investors, outweighing any efficiency gains and ultimately raising costs to consumers overall.

This project has explored options for evolutionary reform within the existing decentralised national market design.

We have not focused on locational investment efficiency in this work since we consider that on this aspect the benefits of zonal pricing could be replicated through more centralised spatial planning of networks, connected assets, and infrastructure in adjacent sectors, and government or regulatory targeting of support contracts for renewables, interconnectors and flexibility providers. We have therefore focused on operational efficiency as the area in which most of the potential benefits of zonal pricing could arise. Our assessment and previous work have shown that most of these operational efficiency benefits would result from improved operational efficiency of interconnectors, small-scale and storage assets.

Overall, our view is that an enhanced national market design could deliver positive benefits rapidly with limited downside risk. The alternative option of a zonal market has a wider range of outcomes, with higher possible benefits but also potentially resulting in significant net overall costs.

The Enhanced National and Enhanced National Stretch market designs are summarised in Exhibit 1.1. These reflect different degrees of change to interconnector arrangements: an ‘Enhanced National’ world in which any changes are subject to bilateral discussion between the countries concerned (TSOs, potentially with some national political agreement) and an ‘Enhanced National Stretch’ world in which – we believe – the application of the Trade and Cooperation Agreement (TCA) would need to be clarified and/or (potentially) UK-EU agreement would be needed[3].

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[1] Review of Electricity Market Arrangements, Autumn Update (DESNZ, December 2024) https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-autumn-update-2024

[2] Review of Electricity Market Design in Great Britain, Phase 2 Public Summary Report (AFRY, August 2023) https://afry.com/sites/default/files/2023-12/gb_electricitymarketdesign_phase2_publicsummaryreport_v500.pdf

[3] We have excluded topics which we believe would not be possible within the existing TCA, although in the end the boundaries could only be established firmly by negotiation.

Exhibit 1.1– Summary of the Enhanced National and Enhanced National Stretch market designs

Building block		Enhanced National	Enhanced National Stretch
Management of interconnectors	Pre-gate closure: Expanded NESO countertrading on interconnectors	1 Improved NESO access to interconnector assets ahead of gate closure through more frequent explicit capacity auctions on all interconnectors and the introduction by NESO of 24/7 trading	9 Expanded NESO potential to secure earlier and more cost-effective interconnector countertrades without the possibility of subsequent unwinding by other market participants
	Post-gate closure: Expanded NESO use of interconnectors in balancing timeframes	2 Improved NESO access to interconnector assets post gate closure through expansion of SO-SO trading	10 Improved NESO access to interconnector assets post gate closure through improved cross-border balancing via a bilateral cross-border balancing platform (or via direct nomination between SOs)
Management of small-scale assets	Improved FPNs	3 Increased NESO visibility of BMUs through incentives to improve accuracy of Final Physical Notifications (FPNs)	
	Improved NESO optimisation of small-scale BMU assets	4 Improved NESO forecasting tools and optimisation processes to improve NESO access to small-scale BMU assets in balancing and redispatch	
	Lowering of BMU threshold to 10MW	5 Improved NESO visibility of and access to a larger number of small-scale assets through lowering of the capacity threshold for mandatory participation in the Balancing Mechanism to 10MW for new assets (but not retrospectively for existing non-BMU assets)	
	Improved NESO visibility and access to non-BMU assets	6 Improved NESO visibility and access to remaining non-BMU distribution-connected assets through: improved information provision to the SO in short-term planning and operational timeframes; extension of arrangements for NESO access to non-BMU resources (e.g. constraints management markets); and reduced barriers to voluntary participation in the Balancing Mechanism and other balancing services	
Management of storage assets	Improved information sharing between NESO and storage assets	7 Improved information sharing between NESO and storage assets on system requirements and dispatch expectations (e.g. unit commitment, profile of battery charge and discharge) to support more effective NESO within-day optimisation over extended periods.	
	Improved NESO market arrangements for optimisation of storage assets	8 Improved management of intertemporal issues through the capability for NESO to 'commit' usable energy from storage assets ahead of gate closure	

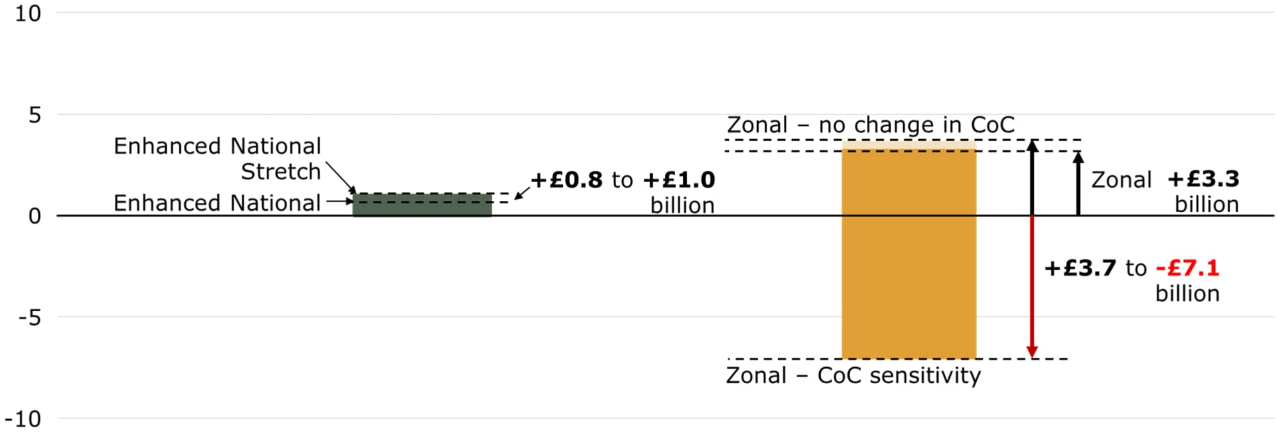
Quantified market elements

The differences in economic welfare between today's national business-as-usual and the Enhanced National, Enhanced National Stretch and Zonal alternative cases are shown in Exhibit 1.2[4].

We find that adopting the Enhanced National market design achieves a positive overall economic welfare benefit relative to current arrangements of £0.8 billion (NPV 2030-2050, 3.5% discount rate), which increases to £1.0 billion in the Enhanced National Stretch case.

The alternative Zonal case shows positive welfare benefit of £3.3 billion, but within a range from of £3.7 billion benefit to a -£7.1 billion disbenefit, depending on the impact of risk on the cost of capital.

Exhibit 1.2 – Range of total economic welfare benefit, Enhanced National and Zonal cases versus National BAU (Net Present Value, £billion real 2023)



Notes: All figures are based on Net Present Value over the period 2030 to 2050, with a 3.5% discount rate. The Zonal case assumes a 100bps increase in hurdle rate for non-CfD supported thermal capacity (+50bps for OCGT). The Zonal – CoC sensitivity case assumes that in addition hurdle rates for CfD-supported capacity increase by 100bps; the Zonal – no change in CoC sensitivity removes all increases in hurdle rates from the Zonal case.

Of the enhancements to a national market design which we have considered, improved arrangements for interconnection have the largest potential to deliver benefits.

Changes to interconnection arrangements cannot be implemented unilaterally, and would require collaboration between transmission system operators (with political support where needed) to bring mutual benefit.

[4] In all cases, the total economic welfare figures exclude implementation costs, which are expected to be higher (and a significant share of the modelled benefit) in the Zonal case. Additionally for the Zonal cases, the economic welfare figures also exclude potential negative impacts from the following: imperfect foresight of transmission constraints at the day-ahead stage; imperfect day-ahead market coupling; any impacts from reduced liquidity; any additional ongoing costs for trading and hedging; and any negotiated mitigations of the wealth transfers from interconnected markets to GB.

The operation of interconnectors is a matter for mutual agreement with neighbouring TSOs but the principles are defined by the UK-EU Trade and Cooperation Agreement (TCA) and the EU's own market design.

We note the recent statement by Government that "there is very little that can be done unilaterally in GB under reformed national pricing to improve the flow of interconnectors"[5], however we believe significant improvements to interconnector flows could credibly be achieved through negotiation to expand the flexible use of interconnection for mutual benefit.

Some interconnector arrangements might relatively easily be changed to accommodate our recommendations with the agreement of the counterpart country. We believe that significant gains could be achieved bilaterally (without EU negotiations) by expanding existing arrangements for intraday countertrading.

Further gains could be achieved with innovations on the use of interconnector capacity restrictions to enable earlier countertrading, although these are more likely to require re-interpretation of the EU-UK Trade and Cooperation Agreement (TCA).

We have not taken legal advice on interpretation of the TCA, nor do we offer any. The TCA itself is up for renewal in 2026 but may be rolled over until 31st March 2028. We believe that the introduction of zonal pricing would also require discussion under the TCA.

As an enduring solution, we believe that it would be possible to retain explicit auctions for countertrading alongside implicit coupling arrangements; countertrading could also operate with implicit coupling by creation of a capacity product for use within the market coupling (auction or continuous).

Currently most GB interconnectors have arrangements for capacity allocation based on explicit capacity auctions. The only interconnectors currently with implicit capacity allocation are those to Ireland and Norway.

Under the TCA it is intended that Great Britain achieves a degree of market coupling via Multi-Region Loose Volume Coupling (MRLVC) using implicit auctions, although progress has been slow to date. A return to implicit price coupling is unlikely in the foreseeable future, although not completely impossible in the long-term.

There are two possible ways for NESO countertrading to remain an enduring solution with implicit capacity allocation. We believe both are feasible, but each would require European agreement.

- explicit auctions for countertrading alongside implicit coupling arrangements
- under an alternative approach, the market operator for the implicit coupling would offer a new product setting a specific price for the capacity

[5] Review of Electricity Market Arrangements, Autumn Update (DESNZ, December 2024)

product itself[6]. This would be used in the algorithm to determine prices and flows.

Any changes to interconnector arrangements must be mutually beneficial for both countries and must be within– or within the interpretation of – the terms of the EU-UK TCA.

The unliteral introduction of zonal pricing would potentially have larger impacts on interconnected markets than those under reformed national pricing.

The possible introduction of a zonal market in Great Britain would also have a significant impact on interconnected EU markets. Although we have not explored this issue, the introduction of a zonal market would be unlikely to avoid the need for negotiation with interconnected markets and likely to form part of the renegotiation of the TCA due in 2026. Unlike the welfare benefits in the enhanced national market designs, a significant portion of the economic benefit to Great Britain of the Zonal case (including £0.8 billion of redispatch profits lost by overseas producers) results from a redistribution of welfare from non-GB parties, and this theoretical benefit could be reduced or removed depending on the outcome of EU negotiations. Other changes are also afoot including the possible application of the EU Carbon Border Adjustment Mechanism to GB electricity exports, which could dwarf the effect of REMA.

The potential welfare gains from improvements for small-scale and storage assets are smaller but more easily achieved than changes for interconnectors.

We propose enhancements to market arrangements for both small-scale and storage assets, including better access to these resources and improved forecasting and optimisation tools. Change is ongoing, especially for the set of information and tools which NESO uses to predict and (where relevant) to optimise the patterns of use of smaller scale assets. Many of the required changes are already under development by NESO.

We have examined two variants of the Enhanced National case, one based on applying only the changes to interconnection, and the other based on applying the changes related to small-scale and storage assets only. The results of these variants are shown in Exhibit 1.3.

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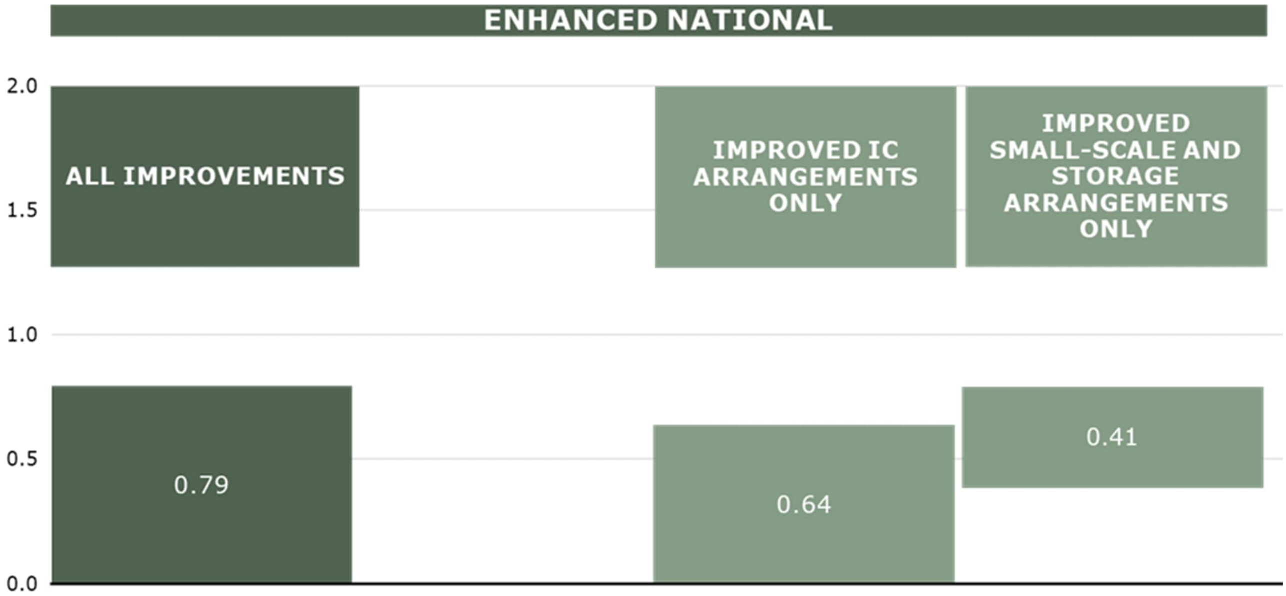
[6] AFRY (then Pöyry) created this idea in 2013, as part of a body of work on flexibility and the allocation of network capacity between market timeframes: day-ahead, intraday and balancing, and presented at the Florence Forum in 2014. Within that work we noted the possible application to congestion management by the TSOs. See woodhouse_florence_forum_20140520_v_1_0.pdf.

Exhibit 1.3 – Total economic welfare benefit, Enhanced National and variants with partial improvement versus National BAU (Net Present Value, £billion real 2023)



Notes: All figures are based on Net Present Value over the period 2030 to 2050, with a 3.5% discount rate.

Of the total welfare of £0.79 billion in the Enhanced National, the variants indicate that most of the benefit (£0.64 billion) is potentially achievable through improved arrangements for interconnection alone. The welfare benefit from improved arrangements for small-scale and storage assets alone are also significant, amounting to around two-thirds (£0.41 billion) of the total benefit of the Enhanced National case. Considered in isolation from each other, the impacts of changes to arrangements from small-scale and storage assets are smaller than those from interconnectors[7].

Having multiple possible routes to achieving a significant share of the potential gains also adds a degree of robustness to the likelihood of achieving a significant share of the potential; failure in one area does not mean all (or even most) of the potential gains are lost.

Other potential areas of reform (e.g. reformed access rights for storage assets and constraint management markets) could provide some further operational efficiency gains as part of an Enhanced National market, although these have not been quantified.

Many of the ideas in this report are already being progressed by NESO, and we commend NESO for the impressive range of initiatives it currently has under development to improve existing arrangements[8]. Building on these

[7] These results show that welfare changes resulting from individual changes to arrangements are not additive; the welfare changes are dependent on the order that changes in assumptions about the effects of market design are applied.
[8] The latest Balancing Cost Portfolio update gives an indicative summary (NESO, February 2024) https://www.neso.energy/document/288791/download

developments will have enduring value whether or not a zonal market is eventually implemented.

Although higher than those achieved in either the Enhanced National or Enhanced National Stretch cases, the operational benefits arising from a possible move to a zonal market are relatively small in a scenario with an appropriate level of network build

Grid build will reduce the effects of (and the need for) zonal pricing, and plans for rapid reinforcement of the grid are now in train. The estimated £20 billion programme of work approved by Ofgem under the ASTI programme was an important marker[9]. The recently published Government plan to decarbonise the power grid by 2030 is based deploying more transmission reinforcement in 5 years than has been accomplished in the past decade, enabled through an improved planning and consenting environment and potentially a tightened regime of penalties on network owners[10]. The removal of the ban on onshore wind developments in England[11] has also removed a major restriction on the ability of new generation to locate nearer demand, helping to limit the growth of network constraints.

Improved operational efficiency could be achieved with an enhanced national market, with lower investment related risk and disruption for market participants than under a move to a zonal market.

An Enhanced National or Enhanced National Stretch market design would be likely to deliver, sooner and more reliably, a significant share of the operational efficiency gains of a zonal market without the downsides, and is unlikely to deliver a negative outcome overall. The alternative option of a zonal market has a wider range of outcomes, with higher possible benefits but also potentially an overall worse outcome depending on the effectiveness of the markets and the impact on cost of capital.

The Enhanced National or Enhanced National Stretch market design may also enable efficiency gains to be realised sooner than a zonal market alternative, as the need to develop an extensive risk management framework and grandfathering of existing rights to deal with wealth transfers is avoided. The need for EU-level negotiation would also be avoided in the Enhanced National case (and might be in the Enhanced National Stretch case, although this is less likely).

[9] https://www.ofgem.gov.uk/press-release/proposed-anglo-scottish-electricity-superhighway-power-millions-homes-first-progress-through-fast-track-ofgem-process
[10] Clean Power 2030 Action Plan (DESNZ, December 2024)
[11] Policy statement on onshore wind (DESNZ, July 2024) https://www.gov.uk/government/publications/policy-statement-on-onshore-wind/policy-statement-on-onshore-wind

Recommendations

We recommend that:

- the Enhanced National Stretch market design is progressed; in event the additional elements within the Enhanced National Stretch design were not delivered, the Enhanced National design would result as a fallback option. Many of the required changes are already in development and can be delivered ahead of any properly managed introduction of a zonal market;
- there should be rapid development of measures to improve operational (and investment) efficiency within the existing national market, particularly in the areas identified in this report;
- in particular, there should be recognition that improvements to interconnector arrangements are needed for both zonal and enhanced national market designs; these should be pursued bilaterally and where necessary at European level, within the existing the EU-UK TCA; and
- the impact of the impact of network build on the benefits of zonal should be recognised, and co-ordinated grid build accelerated as planned.

1 Introduction

The Department for Energy and Net Zero (DESNZ) launched its Review of Electricity Market Arrangements (REMA) in July 2022, covering nearly all aspects of electricity market design in Great Britain, with the objective of ensuring they remain suitable for achieving full decarbonisation of the grid by (at that time) 2035. AFRY's previous multiparty quantitative study on specific options for locational energy markets concluded that an evolutionary rather than a revolutionary approach would be advisable, given the need to maintain investment without any delay to meet the ambition of a fully decarbonised power grid by 2035. We found that the small-but-material operational efficiency gains which might arise from zonal pricing might be outweighed by new risks on investors which would increase the cost of capital and ultimately costs to consumers.

The second REMA consultation was published by DESNZ in March 2024, ruling out further consideration of nodal pricing. With a move to greater centralised planning of both generation capacity and network reinforcement locations, the requirement for the energy market to level locational investment signals has reduced in importance; locational investment signals are in any case more easily replicated in a national market (for example through suitable long-term transmission charging arrangements). However, a zonal market has potential to also provide operational efficiency benefits, and there has been less clarity on how far operational efficiency improvements within a national market could approach those delivered by a zonal market.

Since the second REMA consultation, DESNZ has been working on a programme to develop options for both zonal pricing and improved operational incentives for a national market, along with further consideration of a possible move to centralised dispatch.

AFRY has previously undertaken a detailed examination of the sources of inefficiency in the current scheduling and dispatch arrangements[12]. We have subsequently undertaken separate work on high-level market design options that could address some of these inefficiencies, comprising permutations of national or zonal pricing combined with either centralised or decentralised dispatch[13].

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[12] GB scheduling and dispatch – a case for change, a report to NESO (AFRY, May 2024) https://www.neso.energy/document/318431/download

[13] National and Zonal electricity market designs for Great Britain, Summary Report (AFRY, May 2024) https://afry.com/sites/default/files/2024-05/2024_gb_electricitymarketdesign_publicsummaryreport_v100_2.pdf

The REMA Autumn update has indicated that the Government is not minded to further pursue centralised dispatch as a reform option[14]. Across four enduring metrics for market design[15], we also found that the two centralised strawmen (National Centralised and Zonal Centralised) did not score higher than the BAU baseline as long-term solutions, leaving a Decentralised Zonal market or a Decentralised National (Enhanced National) market as the two most credible designs.

We found that, due to its potential for higher operational efficiency, a Zonal Decentralised market could be the best enduring solution, although this would be subject to a major programme of work to introduce suitable grandfathering and risk management frameworks successfully. If the pre-conditions of zonal market implementation cannot be delivered, the best alternative would be improved investment and operational signals within the existing national market framework, combined with a strong focus on delivering appropriate levels of transmission reinforcement.

Consequently, an Enhanced National decentralised dispatch market could be the most attractive option overall, if required measures could be implemented quickly and if the enhancements could achieve a reasonable share of the operational efficiency gains of a zonal market.

This report sets out market design features that could enable improved dispatch efficiency within an Enhanced National market, focusing on improved dispatch efficiency for interconnectors, storage and small-scale assets within an Enhanced National market design, with quantification of the potential welfare gains in comparison with a zonal market case.

This report is the work of AFRY and presents our own views on the ways forward. We are grateful to the 7 industry members[16], who have supported the work, both financially and through their active participation in the debate. We also extend thanks to the 4 observer organisations[17] that have – to varying degrees – joined actively in the discussions of the group. Despite these contributions, this report represents the independent opinion of AFRY, and the opinions may not be attributed to any of the parties who supported the process.

[14] REMA Autumn update (DESNZ, December 2024) https://assets.publishing.service.gov.uk/media/675acc977e419d6e07ce2bc3/rema-autumn-update.pdf
[15] Investment effectiveness, operational efficiency, allocation of cost risk and reward, and enduring robustness
[16] SSE, RWE, Scottish Power, National Grid Ventures, Ørsted, E.ON and Schroders Greencoat
[17] DESNZ, Ofgem, NESO, National Grid Group

2 Enhanced National market designs for operational efficiency

Our Enhanced National market designs for improved operational efficiency are focused on improved arrangements for interconnection, distribution connected and storage assets

We have considered aspects of Enhanced National designs which might improve operational efficiency through possible improvements to scheduling and dispatch arrangements that could be made within an Enhanced National design, based on the following asset-type-specific building blocks:

- management of interconnectors
- management of small-scale[18] assets
- management of storage assets

These blocks contain elements related to both improved NESO access to these asset classes for redispatch or balancing, and improved NESO visibility of both the assets and the overall system state at the time NESO's decisions have to be taken.

The strawmen are each built up from choices on the elements within the market design 'building blocks', as summarised in Exhibit 2.1 below, and described in more detail in the pages that follow.

[18] With installed capacities <100MW and so potentially outside the Balancing Mechanism.

Exhibit 2.1– Summary of the Enhanced National and Enhanced National Stretch market designs

Building block		Enhanced National	Enhanced National Stretch
Management of interconnectors	**Pre-gate closure: Expanded NESO countertrading on interconnectors**	1 Improved NESO access to interconnector assets ahead of gate closure through more frequent explicit capacity auctions on all interconnectors and the introduction by NESO of 24/7 trading	9 Expanded NESO potential to secure earlier and more cost-effective interconnector countertrades without the possibility of subsequent unwinding by other market participants.
	Post-gate closure: Expanded NESO use of interconnectors in balancing timeframes	2 Improved NESO access to interconnector assets post gate closure through expansion of SO-SO trading.	10 Improved NESO access to interconnector assets post gate closure through improved cross-border balancing via a bilateral cross-border balancing platform (or via direct nomination between SOs)
Management of small-scale assets	**Improved FPNs**	3 Increased NESO visibility of BMUs through incentives to improve accuracy of Final Physical Notifications (FPNs)	
	Improved NESO optimisation of small-scale BMU assets	4 Improved NESO forecasting tools and optimisation processes to improve NESO access to small-scale BMU assets in balancing and redispatch	
	Lowering of BMU threshold to 10MW	5 Improved NESO visibility of and access to a larger number of small-scale assets through lowering of the capacity threshold for mandatory participation in the Balancing Mechanism to 10MW for new assets (but not retrospectively for existing non-BMU assets)	
	Improved NESO visibility and access to non-BMU assets	6 Improved NESO visibility and access to remaining non-BMU distribution-connected assets through: improved information provision to the SO in short-term planning and operational timeframes; extension of arrangements for NESO access to non-BMU resources (e.g. constraints management markets); and reduced barriers to voluntary participation in the Balancing Mechanism and other balancing services	
Management of storage assets	**Improved information sharing between NESO and storage assets**	7 Improved information sharing between NESO and storage assets on system requirements and dispatch expectations (e.g. unit commitment, profile of battery charge and discharge) to support more effective NESO within-day optimisation over extended periods.	
	Improved NESO market arrangements for optimisation of storage assets	8 Improved management of intertemporal issues through the capability for NESO to 'commit' usable energy from storage assets ahead of gate closure	

An Enhanced National market design could contain the following elements:

Management of interconnectors:

1. Improved NESO access to interconnector assets ahead of gate closure through more frequent explicit capacity auctions on all interconnectors and the introduction by NESO of 24/7 trading.

2. Improved NESO access to interconnector assets post gate closure through expansion of SO-SO trading.

Management of small-scale assets:

3. Increased NESO visibility of BMUs through incentives to improve accuracy of Final Physical Notifications (FPNs).
4. Improved NESO forecasting tools and optimisation processes to improve NESO access to small-scale BMU assets in balancing and redispatch.
5. Improved NESO visibility of and access to a larger number of small-scale assets through lowering of the capacity threshold for mandatory participation in the Balancing Mechanism to 10MW for new assets (but not retrospectively for existing non-BMU assets).
6. Improved NESO visibility and access to remaining non-BMU distribution-connected assets through: improved information provision to the SO in short-term planning and operational timeframes; extension of arrangements for NESO access to non-BMU resources (e.g. constraints management markets); and reduced barriers to voluntary participation in the Balancing Mechanism and other balancing services.

Management of storage assets:

7. Improved information sharing between NESO and storage assets on system requirements and dispatch expectations (e.g. unit commitment, profile of battery charge and discharge) to support more effective NESO within-day optimisation over extended periods.
8. Improved management of intertemporal issues through the capability for NESO to ‘commit’ usable energy from limited duration assets ahead of gate closure.

A more ambitious Enhanced National Stretch market design would contain the same points as the Enhanced National case, but with the following additions or refinements on interconnection:

Management of interconnectors:

9. Expanded NESO potential to secure earlier and more cost-effective interconnector countertrades without the possibility of subsequent unwinding by other market participants.
10. Improved NESO access to interconnector assets post gate closure through improved cross-border balancing via a bilateral cross-border balancing platform (or via direct nomination between SOs)

Any changes to interconnector arrangements must be mutually beneficial for both countries and must be within– or within the interpretation of – the terms of the EU-UK TCA.

Each of the ten points set out above for Enhanced National market designs are described in more detail in the following pages.

1. Improved NESO access to interconnector assets ahead of gate closure through more frequent explicit capacity auctions on all interconnectors and the introduction by NESO of 24/7 trading

Operational efficiency gains

More frequent intraday capacity auctions (each covering a smaller number of delivery periods) closing as close as possible to real time would maximise NESO's potential to countertrade based on more accurate information about constraints and the costs of alternative actions in the Balancing Mechanism[19]. This is particularly the case for those interconnectors which currently have no explicit capacity auctions at all (those to Ireland and Norway). The introduction of 24-hour-a-day trading capability by NESO would also enable countertrading in the overnight periods in which this is currently not possible.

Ensuring the time of day of the final intraday capacity auction is similar across all interconnectors would facilitate greater competition among market participants bidding for NESO countertrades; liquidity in the intraday market peaks in the hours ahead of gate closure. Both effects should facilitate cost-effective countertrading.

Implementation and risk management

The optimal number of intraday capacity auctions and number of delivery periods per auction would need to be established[20]. Having all intraday auctions closing 2-3 hours ahead of the first delivery period may be feasible, given it is already achieved for many of the existing auctions. A new 24 hour, 7 days a week trading capability would have some implementation and ongoing costs. Although we have not considered implementation costs (one-off or enduring) in this study, these costs are likely to be significantly lower for enhancements to the national market than for the implementation of a zonal market.

As currently set-up, NESO countertrading requires there to be explicit capacity auctions on the interconnectors over which trades are done; we think additional explicit capacity auctions could be implemented relatively easily on interconnectors that already have them.

It is possible in principle to have both explicit and implicit capacity auctions on interconnectors. There are no explicit auctions currently on the Irish interconnectors[21] or on North Sea Link to Norway. Intraday explicit capacity auctions could be introduced, and would need to be the closing capacity auctions.

Mutually beneficial reciprocal arrangements would need to be agreed with the interconnected SOs. Any proposed extensions to the current ability of NESO to alter interconnector schedules close to real time would otherwise

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[19] The quality of NESO countertrade decision making is also by improved visibility of the state of system constraints and the cost of alternative actions, which is supported by the requirements on improved quality of FPNs, and improved information sharing between NESO and market participants listed as points for small-scale and storage assets.
[20] For example, 6 auctions, each covering 4 delivery periods.
[21] The Irish interconnectors have implicit day-ahead and intraday auctions, while NSL has no auctions or trading after the implicit day-ahead auction.

cause concern, perhaps particularly with the Norwegian and Irish SOs which themselves face congested transmission networks. The use of any unscheduled interconnector capacity for reserve and other ancillary services could potentially form part of an agreement.

2. *Improved NESO access to interconnector assets post gate closure through expansion of SO-SO trading*

Currently, post-gate closure redispatch of interconnectors is possible via a SO-to-SO trades for balancing energy on most GB interconnectors (the exceptions are NEMO to Belgium and NSL to Norway). Commercial arrangements for price setting are agreed for three-way commercial agreements between the interconnected SOs and the interconnector owner. Prices are set day-ahead based on predictions of imbalance prices, and trades are also non-firm, so the interconnected SO could reject the trade even if requested at the published price. The non-dynamic pricing (which is generally unattractive to NESO) and lack of firmness tends to result use of SO-SO trades as a last resort for system security issues, although a 25MW tranche is used more regularly on the Irish interconnectors[22] for mutual benefit.

Operational efficiency gains

With expansion of existing provisions on most interconnectors, we believe that incremental gains should be achievable. Greater scope for NESO to select interconnector actions in balancing timeframes would reduce the need for more costly actions from local alternatives in the Balancing Mechanism. Realistically, only a limited volume of interconnector redispatch is likely to be available in balancing timeframes due to low availability and technical constraints in the interconnected markets.

However, expanding SO-to-SO trading to at least a similar level to that with the Irish SO should be achievable, given the small size of Ireland relative to other interconnected markets.

Implementation and risk management

Reciprocal and mutually beneficial arrangements would need to be put in place, requiring appropriate agreements between NESO, the interconnected SO, and the interconnector operator. The discussions should be country-specific and should seek opportunities of benefit to the neighbouring TSO, while addressing any of their serious concerns.

[22] See https://bmrs.elexon.co.uk/soso-trade-prices

3. *Increased NESO visibility of BMUs through incentives to improve accuracy of Final Physical Notifications (FPNs)*

Balancing Market Units (BMUs) submit Physical Notifications (PNs) to NESO that should reflect expected level of output or consumption for each unit, including changes during the day. At gate closure (1 hour before delivery), the PNs become ‘final’ – Final Physical Notifications (FPNs). These are then used for the purposes of taking any required balancing actions in the Balancing Mechanism. Inaccurate FPNs[23] and late changes to PNs reduce NESO’s visibility of the true state of the system in balancing timeframes, leading to unnecessary balancing costs.

Compared to other types of generators, wind generators have tended on average to submit less accurate FPNs (and PNs) than other technologies, causing the most significant additional direct and indirect costs[24].

Operational efficiency gains

Improved accuracy of FPNs would enable NESO to take more efficient balancing decisions, reducing the occasions when unnecessary additional balancing actions occur. Improvements in the accuracy of wind FPNs would lead to particularly significant gains given their relative inaccuracy and the large and growing volume of wind capacity on the system.

Implementation and risk management

NESO already has a programme of work underway to improve the accuracy of information provided by market participants. This has recently resulted in a Guidance Note on the application of good industry practice to ensure the accuracy of FPNs, including quantitative measures of acceptable levels of deviation between FPNs and metered output for wind BMUs, which NESO will monitor[25]. The costs of these measures should be limited for both NESO and market participants.

Going further and introducing a non-zero Information Imbalance charge could improve FPNs through a financial incentive on BMUs to improve accuracy. This would introduce a degree of double penalisation for both portfolio-level imbalance costs and information imbalance at the unit level, and introduce higher costs for intermittent units which are inherently difficult to forecast; a cost-benefit analysis of the level of the charge with the cost of compliance would need to be undertaken.

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[23] PNs can change up to gate closure, but accurate PNs at any given point in time following the Initial Physical Notification submitted at 11.00 day-ahead are also important from an ESO perspective since they inform whether any advance balancing actions are cost effective.

[24] Supplier FPNs are also inaccurate, although NESO does not currently rely on these, instead using its own forecasts of GB National and GB Transmission System Demand.

[25] https://www.neso.energy/document/323451/download

4. Improved NESO forecasting tools and optimisation processes to improve NESO access to small-scale BMU assets in balancing and redispatch

Participation in the BM by small-scale assets has partially been limited by the difficulty to the NESO control room of instructing a large number of small assets in real-time, sometimes resulting in a more expensive larger unit being instructed instead. However, NESO has recently introduced new algorithm-based dispatch tools (through the Open Balancing Platform) to enable dispatch instructions to be issued to multiple small units simultaneously. Some improvements for usage in the BM were observed in 2023. The Open Balancing Platform is intended to replace both the existing Balancing Mechanism and the Ancillary Services Dispatch Platform by 2027.

Longer-term, NESO is examining ways to further improve forecasting of supply and demand to enable more informed decision making, and ways to make dispatch instructions more efficient and faster. Use of artificial intelligence to dynamically set reserve requirements[26] and adaptive machine learning to optimise dispatch under forecast uncertainty[27], including of multiple distributed assets, are already under consideration. NESO is building experience of dispatching aggregated units, including a BMU entirely from EV chargers and also from the use of the Demand Flexibility service.

Operational efficiency gains

Increases in the ability to see and co-ordinate many small offers from small-scale assets would improve NESO's ability to rely on disaggregated resources to meet balancing needs at lower cost.

Implementation and risk management

A significant modernisation programme by NESO is under already way to give the control room the tools to manage distributed resources. The main costs of implementation would fall on NESO to develop and maintain the improved algorithms and supporting software interfaces.

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[26] Probabilistic Machine Learning Solution for Dynamic Reserve Setting: https://smarter.energynetworks.org/projects/nia2_ngeso003/
[27] Advanced Dispatch Optimisation https://smarter.energynetworks.org/projects/nia2_ngeso0013/

5. *Improved NESO visibility of and access to a larger number of small-scale assets through lowering of the capacity threshold for mandatory participation in the Balancing Mechanism to 10MW for new assets (but not retrospectively for existing non-BMU assets)*

Currently, all transmission connected assets must submit PNs and participate in the BM regardless of size, but only distribution connected assets larger than a threshold capacity (100MW in England and Wales, 30MW in south Scotland and 10MW in north Scotland) are required to submit PNs and participate in the Balancing Mechanism. Participation of distribution-connected assets with capacities smaller than these thresholds is voluntary[28].

Operational efficiency gains

If NESO gained access to a larger set of resources in the Balancing Mechanism, it should enable a range of potentially lower cost actions to be taken. Wider participation in the Balancing Mechanism would also give NESO more direct visibility of the state of the system at each location through more capacity submitting Physical Notifications (PNs), enabling better forecasting of network constraints and improved ability to make redispatch decisions more generally.

Implementation and risk management

There is already a Grid Code modification proposal[29] (GC0117) to this effect which is under active consideration (proposed to be effective from June 2027). It would take time to realise significant efficiency gains, since the new threshold would apply only to new assets.

Some additional costs would inevitably be imposed on new assets caught by the lower threshold, for applications and ongoing information sharing and metering requirements; managing more BMUs with agreements and increased data volumes would also lead to some additional costs for NESO. The cost-benefit analysis is yet to be undertaken.

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[28] Voluntary participation by distribution-connected assets is limited to those with a capacity above 1MW, including for those registered as Secondary BMUs under Virtual Lead Parties. NESO is currently trialling up to 300MW of capacity consisting of aggregations of units with capacities less than 1MW to assess the impacts on system operation of relaxed metering requirements: https://www.neso.energy/document/308661/download.
[29] Grid Code Modification Proposal GC0117: Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of Power Station requirements | National Energy System Operator. Alternative modifications are also under consideration, some of which would even raise existing thresholds. GC0117 is on hold 7 pending the outcome of the ESO Balancing Transformation Strategic review.

6. *Improved NESO visibility and access to remaining non-BMU distribution-connected assets through: improved information provision to the SO in short-term planning and operational timeframes; extension of arrangements for NESO access to non-BMU resources (e.g. constraints management markets); and reduced barriers to voluntary participation in the Balancing Mechanism and other balancing services*

For distribution-connected assets not registered as BMUs, NESO has no visibility of their planned output in planning and operational timeframes. This share of generation (which is not required to submit PNs) is seen indirectly and late by ESO, as a change in national demand (total demand net of embedded (non-BMU) generation). The uncertainty in the demand that ultimately has to be balanced in real time results in potential for over- and under-procurement of energy and reserve through the day, and ultimately can lead to inefficient dispatch decisions.

Operational efficiency gains

Improved visibility of and access to non-BMU scheduled output would give NESO greater ability to take better informed contingency actions, with operational efficiency gains resulting from reduced instances of over-procuring reserve to cover a contingency that didn’t materialise, or under-procuring resulting in a need to take expensive actions close to real time.

Arrangements to harness the flexibility of non-BMU resources without the need for full BM participation should enable NESO to utilise an additional tranche of potentially lower cost resources in managing the system.

Equally, incentives and/or reduced barriers to participate in the Balancing Mechanism on a voluntary basis – including ensuring that metering arrangements are suitable for aggregated small-scale resources – would increase direct NESO access to remaining non-BMU resources, as well as their visibility.

Implementation and risk management

There are various ways in which improved information provision could be implemented. The ENA’s Open Networks Project includes a workstream on Operational DER Visibility and Monitoring[30] to improve visibility towards DSOs, and this could be one pathway towards improved information sharing with NESO. There would be some additional costs for improved information provision for NESO, DSOs (if that path is chosen) and participant system upgrades, and on metering for embedded generators.

Various initiatives are already underway to develop tools that enable greater NESO visibility and access to non-BMU resources. The Local Constraint Market trial to manage constraints on the B6 boundary continues to develop improved incentives for participation of non-BMU resources[31], and a broader initiative to develop short-term and long-term

[30] ON21-WS1B-P6 DER Use cases, volumes, and functional specifications (13 Dec 2021) Published.pdf

[31] https://www.neso.energy/industry-information/balancing-services/local-constraint-market

constraints management markets further is underway via the Constraints Collaboration Project. Existing flexibility services provided by non-BMUs (e.g. the Demand Flexibility Service[32]) would help provide a template for implementation. Subject to a full cost-benefit analysis and any necessary market power mitigations, NESO should redouble efforts to develop these tools to further enable the inclusion of non-BMU resources in redispatch.

One major barrier to voluntary participation in the Balancing Mechanism is the metering regime required of BMUs, which is proportionally more expensive for smaller units. Relaxation of metering requirements to be less onerous and expensive would likely increase voluntary participation, although with some reduction in visibility to NESO compared with current metering requirements. NESO is currently exploring this trade-off in a trial of aggregated sub-1MW providers with reduced accuracy and frequency of meter data[33].

Voluntary participation in other balancing services by non-BMUs can be facilitated by lowering barriers to entry, and sharing by NESO of information on potential opportunities, both of which are facilitated by NESO's Power Responsive Programme which continues to expand the potential for increased volumes of non-BMU flexibility for an increasing number of NESO requirements[34].

[32] https://www.neso.energy/industry-information/balancing-services/demand-flexibility-service-dfs
[33] Increasing flexibility from small-scale assets (<1MW) in the Balancing Mechanism https://www.neso.energy/document/303336/download
[34] Power Responsive Programme https://www.neso.energy/industry-information/balancing-services/power-responsive

7. *Improved information sharing between NESO and storage assets on system requirements and dispatch expectations (e.g. unit commitment, profile of battery charge and discharge) to support more effective NESO within-day optimisation over extended periods*

Currently, the energy-limited nature of storage units leads to uncertainty when NESO is making 'advance' scheduling decisions. Given the lack of information with respect to the State of Charge (SoC) of storage units, the capability of these assets and the implications of a dispatch decision on future periods cannot be known with certainty by NESO.

Operational efficiency gains

Improved visibility to NESO of the current state of charge of storage assets would provide improved confidence on their ability to deliver on an instruction in the BM, and increase their utilisation when they are the lowest cost option. Improved information provision by NESO on forecasted constraints could also enable storage assets to be in a more optimal position to help resolve them.

Implementation and risk management

Grid Code modification proposal[35] (GC166) proposes new dynamic data parameters for submission by storage assets, including related to limitation on maximum bids and offers that can be met and future state of energy[36] (proposed to be effective from Q2 2025).

There is a potential risk of gaming through NESO providing more information about constraint forecasts to the market; if units can anticipate the dispatch instructions from the control room and submit expensive offers, there is a risk that operational efficiency (or total cost to customers) could be made worse rather than enhanced. Improved information sharing by NESO would have to be complemented by suitable market-power mitigations. The Transmission Constraint Licence Condition (TCLC) to prevent excessive gains from exploitation of transmission constraints continues to be updated (with refreshed guidance published in June 2024[37]), and provided this is backed by a credible enforcement regime it should be a significant safeguard against gaming of transmission constraints.

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[35] Grid Code Modification Proposal GC0166: Introducing new Balancing Mechanism Parameters for Limited Duration Assets.
[36] Maximum Delivery Offer, Maximum Delivery Bid and Future State of Energy.
[37] https://www.ofgem.gov.uk/sites/default/files/2024-06/TCLC_guidance_10June24.pdf

8. Improved management of intertemporal issues through the capability for NESO to 'commit' usable energy from limited duration assets ahead of gate closure

To improve certainty for NESO about the 'usable' energy for future settlement periods a new market instrument is required. This would enable NESO to formally commit units over a longer time-horizon than the next two settlement periods.

Operational efficiency gains

The ability of NESO to commit storage over multiple periods would remove a further barrier to its utilisation in the BM, further improving utilisation and the costs of balancing.

Implementation and risk management

NESO has an extensive programme of work underway to reduce the underutilisation of storage assets due to 'skipping' in the BM[38], including new reserve services[39] to be delivered through the Open Balancing Platform. This will also soon include improved management of transmission constraints within through interface with the Network Control Management System (NCMS) to calculate constraint limits in real time, and the national optimisation capability for balancing across all zones over longer timeframes.

Development of new multi-period products in the BM or outside the BM for storage assets would enable NESO to commit usable energy ahead of gate closure.

A multi-period product design could be analogous to the Balancing Reserve product, but with the following distinguishing features:

- locational constraints, in order that NESO can select storage bids/offers to help resolve constraints
- products defined for intraday rather than (or in addition to) day-ahead
- a duration constraint so that e.g. a plant with an accepted offer would need to maintain output for e.g. 4 hours

[38] NESO Defining, measuring, and addressing skip rates https://www.neso.energy/document/348236/download
[39] Quick and Slow Reserve services.

9. Expanded NESO potential to secure earlier and more cost-effective interconnector countertrades without the possibility of subsequent unwinding by other market participants

NESO currently executes countertrades on those interconnectors for which there are explicit capacity rights. Currently NESO is (in practice) unable to countertrade on these interconnectors other than in the last (intraday) capacity auction; any countertrade releases an additional net flow capacity in the market flow direction, which (given a subsequent opportunity to trade) other market participants would invariably use to re-increase the flow in market flow direction, undoing (or unwinding) the intended effect of the countertrade in reducing net flows.

For markets with implicit rights as currently implemented, countertrades cannot be executed.

Currently, Net Transfer Capacity (NTC) restrictions may be applied by SOs intraday to limit the available capacity on an interconnector in a particular direction and for particular periods, limiting the market-based flows that would otherwise occur.

Under this enhanced market design element, we propose that NESO (and the counterparty TSO) should have access to countertrading at an earlier stage, both for those interconnectors which currently have explicit capacity auctions, and for those which implicit auctions are used, using a new method. For now, the implicit connections are to Ireland and Norway, but implicit coupling will likely apply to other interconnectors if the move to Multi-Region Loose Volume Coupling is applied as envisaged by the TCA.

There are two possible ways for NESO to secure earlier and more cost-effective interconnector countertrades. We believe both are feasible, but either would require European agreement.

- Counter-trading in conjunction with novel use of NTC restrictions Under one possible approach, any countertrade by NESO (or the other TSO) on a market with either explicit or implicit market coupling would be accompanied by a simultaneous reduction in the NTC available to the market.
- Counter-trading using an explicit capacity product Under an alternative approach for interconnectors with implicit coupling, the market operator for the implicit coupling would offer a new product setting a specific price for the capacity product itself[40]. This would be used in the algorithm to determine prices and flows.

The use of NTCs to secure countertrade volumes is currently in use as part of recently introduced SO-to-SO countertrading arrangements between Denmark and Germany, enabling that German SO (TenneT) to reduce

[40] AFRY (then Pöyry) created this idea in 2013, as part of a body of work on flexibility and the allocation of network capacity between market timeframes: day-ahead, intraday and balancing, and presented at the Florence Forum in 2014. Within that work we noted the possible application to congestion management by the TSOs. See woodhouse_florence_forum_20140520_v_1_0.pdf.

import flows from Denmark, rather than curtailing domestic wind generation to manage internal transmission constraints. The new arrangements are based on TenneT requesting a volume of countertrades (with an associated maximum cost based on alternative domestic actions) which the Danish SO (Energinet) offers (via a third party) into the intraday market, accepting the most cost-effective bids from market participants. The countertrade volume is locked in by TenneT reducing the cross-border NTC (DK1 to DE) within the intraday market coupling algorithm[41]. The new arrangements have been fully operating since July 2023, and have been successful in accommodating a large volume of countertrading at a modest premium to intraday prices[42]. The SO to SO nature of the arrangement could also have potential benefits compared to the existing arrangements which are limited to registered interconnector parties rather than all participants in the intraday market, and in reducing the complexity for countertrading for the NESO control room.

Operational efficiency

Earlier countertrades would potentially enable the majority of NESO actions to be visible to interconnected SOs at an earlier stage than the last (intraday) auction, making the change in flows easier to manage and enabling a greater volume of trades overall. Earlier trades would also potentially enable NESO to secure them at lower cost, compared to nearer to real time when there may be a premium.

With appropriate agreement on both sides, there is potential for any unused interconnector capacity to be used as a reserve product. Any interconnector capacity released through countertrading has the potential for use as a balancing resource, reserve or response product (including for high frequency response for the exporting market). Integration of countertrading and these shared reserve services should be investigated further.

Implementation and risk management

NESO's visibility of system constraints, interconnector flows and the need for and cost-effectiveness of countertrading is less certain in earlier timeframes, particularly before the outcome of the day-ahead power market auctions. Identifying the reverse flow direction is difficult much ahead of the day-ahead stage, and short-term changes occur within the day as markets change.

Novel use of NTC restrictions in conjunction with countertrading could be envisaged on both interconnectors with explicit and implicit capacity allocation auctions; in the case of implicitly allocated interconnectors, an alternative mechanism is for an explicit capacity product to be made available which could work even in conjunction with continuous implicit allocation. At least in principle, countertrading has the potential to

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[41] Methodology for procurement of countertrade energy, p.30 (Energinet, December 2021) https://energinet.dk/media/jeip4p5f/the-methodology-for-procurement-of-countertrade-energy-adjusted-after-public-consultation.pdf
[42] https://energinet.dk/om-nyheder/nyheder/2024/07/11/ny-model-for-modhandel-sikrer-ikke-blot-mere-gron-energi-men-ogsa-store-okonomiske-gevinster/

remain an enduring tool, even in the event of future full implicit coupling on all GB interconnectors.

Currently, NTC restrictions are used by NESO as a last resort to resolve system security issues when no other intraday options are available[43]. However, where an agreement already exists, expansion of NTC restrictions to facilitate countertrading would be expansion of an existing tool, and so could be simple from a process perspective.

As a restriction on capacity in a given direction, an NTC restriction can only prevent capacity sales in a certain direction. At maximum, a NESO NTC restriction could keep the net flow position at zero, but not move it to full export (or import). This would limit the scope of NESO countertrade volumes on the occasions when achieving a reversal of flow from a countertrade would be desirable. Coupling an NTC with a countertrade offers greater flexibility as the countertrade could establish a flow level in a particular auction, with the NTC then preventing that position being unwound in subsequent auctions.

Article 311 of the Trade and Cooperation Agreement (TCA) between the European Union and the UK requires that “the maximum level of capacity of electricity interconnectors is made available, respecting the need to ensure secure system operation; and the most efficient use of systems” and “electricity interconnector capacity may only be curtailed in emergency situations and any such curtailment takes place in a non-discriminatory manner”. The use of NTC restrictions in conjunction with countertrading therefore has a potential interaction with the Trade and Cooperation Agreement, and agreement on interpretation would be beneficial ahead of any implementation. However, it is at least arguable that the use of an NTC restriction to lock in a NESO countertrade is not a curtailment of interconnector capacity available to the market, given that the NESO countertrade (which is permitted under the TCA) is the sole reason that the potential market opportunity for other market participants to do another trade in the reverse (market) direction arises. In addition, an NTC restriction implemented simultaneously with a countertrade could be seen as a form of market-based reserve procurement by NESO (particularly if appropriate reserve sharing arrangements are built alongside any unused interconnector capacity).

NTC restrictions require three-way agreement between NESO, the interconnected SO and the interconnector owner, resulting in additional complexity for countertrading.

[43] https://www.neso.energy/document/315901/download

10. *Improved NESO access to interconnector assets post gate closure through improved cross-border balancing via a bilateral cross-border balancing platform (or via direct nomination between SOs)*

NESO's ability to manage interconnectors post-gate closure would be improved through a cross-border balancing platform or ability for interconnected TSOs to directly nominate interconnector flows. Both would involve both SOs sharing balancing product and price information with the other SO, enabling real-time comparison of non-domestic balancing resource and prices with domestic options, enabling more efficient utilisation of interconnected resource by NESO.

Operational efficiency gains

Improved NESO access to a larger number of potentially lower cost resources across interconnected markets in balancing timeframes, with pricing more accurately reflecting real-time system conditions, should result in operational efficiency gains on both sides.

Implementation and risk management

As with other measures related to interconnectors, implementation would be dependent on achieving cooperation between SOs through opportunities for mutual benefit.

There is provision within the TCA to develop a bespoke GB-EU balancing platform in place of participation in TERRE or MARI (from which GB is explicitly banned under the TCA), and potential appetite from interconnected SOs to put arrangements in place is indicated from the fact that prior to Brexit, GB was part of the cross-border balancing initiative with continental SOs.

Implementation would be complex due to the need to coordinate competition between the different balancing markets and the lack of harmonised balancing products between GB and EU; a loosely volume-coupled cross border balancing platform would be more complex to implement than the equivalent in the day-ahead market, which has itself proved difficult to implement.

3 Socio-economic welfare summary

3.1 Introduction

3.1.1 Socio-economic welfare and operational efficiency

The focus of this study has been to examine the ways in which improved operational efficiency could be achieved within the existing decentralised national market design, given the alternative of small but significant efficiency gains previously identified as achievable in a zonal market (albeit with increased disruption and increased risks to investment). We consider that any altered locational investment signals from a zonal market could also be reflected within a national market, especially with spatial planning of energy resources and the range of government support schemes for new technologies, potentially complemented by revised transmission connection and charging arrangements.

Perfect operational efficiency would be achieved if all resources could be dispatched in a perfect least cost merit order, subject to respecting both system constraints and constraints on individual resources. There are several reasons in any market design why this is not achieved in practice, including a lack of perfect information on both system and unit-level constraints held by both market participants and System Operators, and distortions on least cost bidding by market participants for various reasons, including the effect of support schemes and the exercise of any market power that may be exploitable.

In the current national market with a Balancing Mechanism, there are existing limitations on dispatch efficiency (due to market incentives not aligning with system needs, visibility and access to NESO of some resources, and management of intertemporal issues), which AFRY has examined in detail elsewhere[44]. In particular, market participants have limited visibility of transmission constraints due to the national price signal not reflecting them in any market timeframe; resolution of these is then dependent on NESO processes occurring near real-time, which for various reasons are also dependent on limited information about the true state of the system constraints they are trying to address, an incomplete set of resources visible and accessible to NESO for solving these constraints, and imperfect decision making and optimisation processes particularly for small-scale and storage resources.

In this context, the main difference in a zonal market is that transmission constraints are visible to market participants in market timeframes, reflected in zonal price signals which market participants can position against ahead of real time, without perverse incentives to exacerbate constraints (although acting on such constraints would likely breach licence conditions). Although

[44] GB scheduling and dispatch – a case for change, a report to NESO (AFRY, May 2024) https://www.neso.energy/document/318431/download

forecast errors would still result in a residual need for NESO to take actions in the Balancing Mechanism, the size of the problem being solved with centralised processes (which are inevitably limited by the quality of input information, comprehensiveness of the resources within scope and the limitations on achieving perfect optimisation) is greatly reduced – particularly if there is also zonal intraday trading. The differential in efficiency outcomes between a market-based solution and a centralised process solution is the ultimate reason why zonal markets can achieve higher operational efficiency outcomes with respect to solving transmission constraints than a more centralised approach – which includes the current national market with Balancing Mechanism.

As a primary metric of the success of each market design, we have evaluated total economic welfare to Great Britain actors. We believe this should be the primary focus of policy makers, rather than the distribution of gains, given a larger total economic welfare can be reallocated between producers and consumers[45] if obtained, but not otherwise. Previous work has shown that the scale of wealth transfers from producers to consumers from a move to a zonal market has the potential to dwarf the total gains, and extensive grandfathering and risk management arrangements to mitigate these would be a pre-requisite of zonal market implementation[46].

Modelled cases compared

Using a scenario based on NESO's FES 2024 Holistic Transition Pathway, we have modelled four main market design cases for improved operational efficiency:

- National Business-as-Usual (based on continuation of the status quo market arrangements);
- Enhanced National (based on changed arrangements to reflect the market design elements under the Enhanced National heading in Chapter 2;
- Enhanced National Stretch (based on changed arrangements to reflect the additional ambition on interconnector arrangements under the Enhanced National Stretch heading in Chapter 2; and
- a Zonal alternative.

In addition, we have modelled further sensitivities to the Zonal case on delayed implementation and of increases in the cost of capital.

Further details of the modelling approach can be found in Annex B and Annex C.

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[45] Policy and regulatory options for redistribution have not been considered in this study, although would be likely to involve some complexity and cost.

[46] https://afry.com/sites/default/files/2023-12/gb_electricitymarketdesign_phase2_publicsummaryreport_v500.pdf

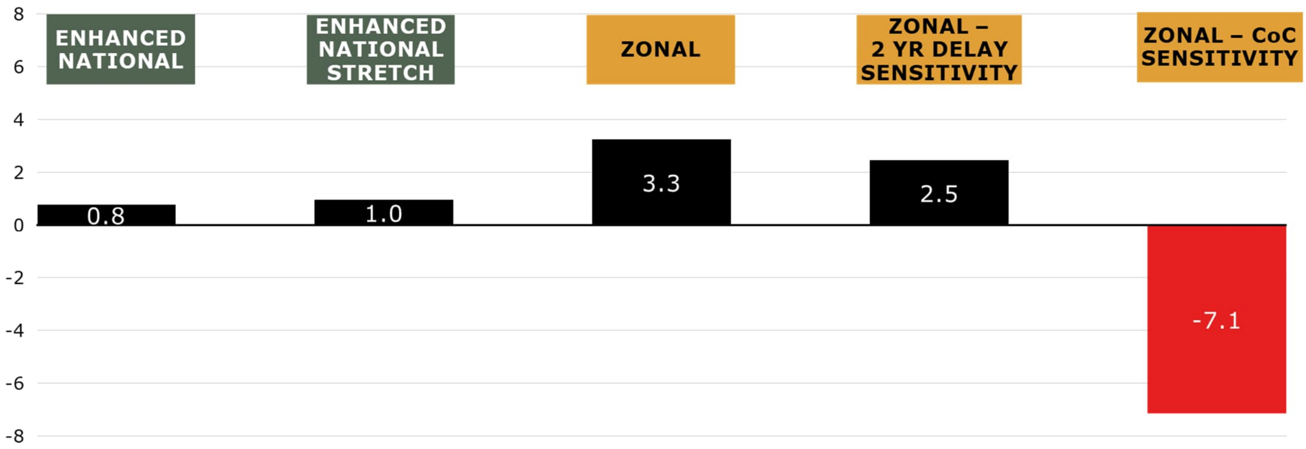
Summary of socio-economic welfare results

The differences in economic welfare between today's national business-as-is and the Enhanced National, Enhanced National Stretch and Zonal alternative cases are shown in Exhibit 3.1. We assume implementation from 2030 in all cases (with the exception of the Zonal – 2-year delay sensitivity, in which the Zonal market is not implemented until 2032). The Enhanced National and Enhanced National Stretch cases both achieve a positive welfare benefit over the period 2030-2050 (£0.8 billion in the Enhanced National, and £1.0 billion in the Enhanced National Stretch case), while the zonal cases show a wider range of between a positive £3.3 billion benefit and a negative -£7.1 billion disbenefit, depending on the impact of increased risk on cost of capital. A 2-year delay to implementation of the Zonal case could also reduce the possible positive benefits by £0.8 billion (c.25%).

In all cases, the total economic welfare figures exclude implementation costs, which are expected to be higher (and a significant share of the modelled benefit) in the Zonal case. Additionally for the Zonal cases, the economic welfare figures also exclude potential negative impacts from the following: imperfect foresight of transmission constraints at the day-ahead stage; imperfect day-ahead market coupling; any impacts from reduced liquidity; any additional ongoing costs for trading and hedging; and any negotiated mitigations of the wealth transfers from interconnected markets to GB.

Overall modelled benefits are small (less than 1%) compared to total consumers bills over the discounting period.

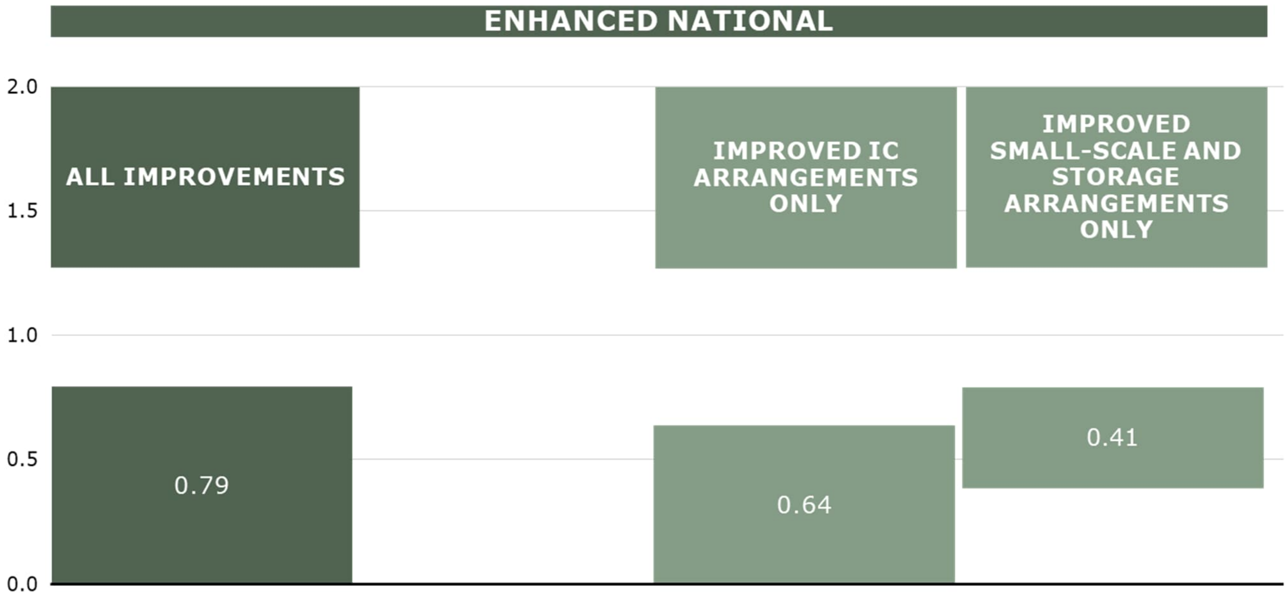
Exhibit 3.1 – Total economic welfare benefit, Enhanced National and Zonal cases versus National BAU (Net Present Value, £billion real 2023)



Notes: All figures are based on Net Present Value over the period 2030 to 2050, with a 3.5% discount rate. The Zonal case assumes a +100bps increase in hurdle rate for non-CfD supported thermal capacity (+50bps for OCGT). The Zonal - 2 year delay sensitivity is identical to the Zonal case, except that implementation occurs from 2032 rather than 2030, with the National BAU case continuing until then. The Zonal – CoC sensitivity is identical to the Zonal case, except that hurdle rates for CfD-supported capacity increase by +100bps. The increase in hurdle rates for CfD-supported capacity required to reduce the welfare benefits in the Zonal case to zero is +31bps (+0.3%).

The positive welfare benefits achieved in the Enhanced National case arise from a combination of market design improvements related to interconnection, small-scale and storage assets. To test the significance of the changes to interconnection versus the other changes, have examined two variants of the Enhanced National case, one based on applying only the changes to interconnection, and the other based on applying the changes related to small-scale and storage assets only. The results of these variants are show in Exhibit 3.2.

Exhibit 3.2 – Total economic welfare benefit, Enhanced National and variants with partial improvement versus National BAU (Net Present Value, £billion real 2023)



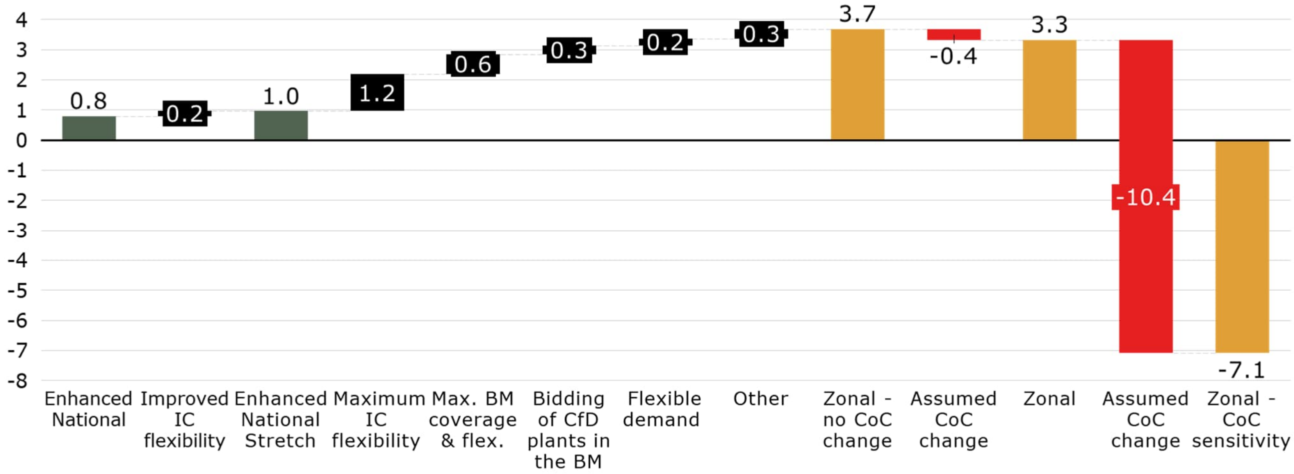
Notes: All figures are based on Net Present Value over the period 2030 to 2050, with a 3.5% discount rate.

Of the total welfare benefit of £0.79 billion in the Enhanced National, the variants indicate that most of the benefit (£0.64 billion) is potentially achievable through improved arrangements for interconnection alone. The welfare benefit from improved arrangements for small-scale and storage alone are also significant, amounting to around two-thirds (£0.41 billion) of the total benefit of the Enhanced National case. Considered in isolation from each other, the impacts of changes to arrangements for interconnection are larger than those from the changes related to small-scale and storage assets.

However, the results also show that welfare changes resulting from individual changes to arrangements are not additive; the welfare changes are dependent on the order that changes in assumptions about the effects of market design are applied. Having multiple possible routes to achieving a significant share of the potential gains also adds a degree of robustness to the likelihood of achieving a significant share of the potential; failure in one area does not mean all (or even most) of the potential gains are lost.

With the caveats about the order of changes in mind, Exhibit 3.3 illustrates some of the main drivers of differences in welfare between the Enhanced National and Zonal cases.

Exhibit 3.3 – Total GB economic welfare benefit differences, National Enhanced, National Enhanced Stretch case and Zonal (Net Present Value, £billion real 2023)



Notes: All figures are based on Net Present Value over the period 2030 to 2050, with a 3.5% discount rate. Total economic welfare benefits shown for each case are based on the differences between welfare case, versus the National BAU baseline.

There are various drivers influencing the differences between the different cases.

For the national cases, in our modelling of the Balancing Mechanism, we assume bid/offer spreads in addition to actual variable costs incurred, which represent a profit to (mainly) producers. When earned by producers in Great Britain, these profits are a transfer from GB consumers to GB producers, but have no impact on overall GB welfare (unlike the variable cost component). To reflect the various tools that NESO can use to change interconnector schedules post the day-ahead stage, we also assume bid/offer spreads for interconnector redispatch. In this case we assume that the profits represented by the bid/offer spreads go to the underlying power plants in the appropriate market[47]. As this results in a transfer from GB consumers to overseas producers, redispatch actions on interconnectors lower total GB welfare (although not pan-European welfare). Consequently, in the Zonal case, £0.8 billion of the £3.3 billion total benefit to GB results from a welfare transfer from overseas producers to GB consumers. This contrasts with the Enhanced National and Enhanced National Stretch cases in which overseas producers are slightly better off (by £0.1 billion and £0.2 billion respectively) due to increased interconnector redispatch payments. For congestion rent we have allocated half the congestion rent to GB.

— Enhanced National to Enhanced National Stretch (+£0.2 billion): The additional improvements to interconnector arrangements pre- and post-gate closure in the Enhanced National Stretch case have been reflected in increased interconnector flexibility through lower bid/offer spreads compared to the Enhanced National. Overall, reduced redispatch

[47] An alternative assumption that could be made is that a share could go to the interconnector itself, with sub-shares going to various countries depending on ownership shares in the interconnector.

costs for domestic plants outweigh increased redispatch costs for interconnectors (which arise from increased redispatch volumes outweighing reduced bid/offer spreads), resulting in an overall gain in GB welfare.

- Enhanced National Stretch to Zonal (+£2.3 billion): There are several drivers of the difference in total welfare between the Enhanced National Stretch and Zonal cases, although the size of each is dependent on the order in which they are applied. Moving from left to right across the chat we have applied the following steps incrementally[48]:
  - *Maximum interconnector flexibility (+£1.2 billion):* In the first step, adding full flexibility of interconnectors to the Enhanced National Stretch results in £1.2billion of additional welfare. Reducing bid/offer spreads on interconnectors to negligible levels enables the maximum potential for interconnector redispatch, and net wealth transfers out of GB as the result of the payment of bid/offer spreads to generators in interconnected markets are reduced to zero[49]. If interconnector countertrades could be secured at an average premium to market prices of less than the €15/MWh assumed in the Enhanced National Stretch case, some of this additional potential welfare may be realisable.
  - *Maximum Balancing Mechanism coverage and maximum flexibility for all assets (+£0.6 billion):* Further adding all assets (including everything below 10MW) to the Balancing Mechanism and also enabling full flexibility (i.e. reducing bid/offer spreads to negligible levels) for all assets results in a welfare addition of £0.6 billion. Some cost savings in the final dispatch are made as a result of a closer approximation to a true cost merit order and access to an increased number of lower cost assets.
  - *Bidding of CfD-supported plants in the BM (+£0.3 billion):* Under the current arrangements, when the wholesale price is above its strike price, a CfD-supported plant behind a transmission constraint is incentivised to bid into the Balancing Mechanism in a way that results in it being constrained off. In the case of wind in Scotland, this reduces the instances when high wind periods are managed by increased interconnector exports to Norway, resulting in lost welfare transfers from Norway to GB (and also reducing pan-European welfare).
  - *Flexible demand (+£0.2 billion):* Price-responsive demand (e.g. from flexible EV charging) responds implicitly to national pricing in the national cases and zonal prices in the zonal cases, and as modelled is assumed to be inflexible within the Balancing Mechanism. This prevents flexible demand from being fully optimised in the national cases. In practice, flexible demand has already begun participating in

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[48] The order in which the steps have been applied is not intended to reflect the likelihood or plausibility of any one step over another.
[49] This represents a theoretical case, as in isolation it effectively assumes plants in other markets do not charge bid/offer spreads for actions in support of GB, but those in GB do, which is an unlikely arrangement.

the market through the Demand Flexibility Service and occasional, supplier-led 'free energy' events which reflect times of low price. NESO has recently begun a trial examining the possibility of EV-charger and heat-pump scale resource being aggregated into a 300MW Balancing Mechanism unit. There is great potential for flexible demand participation to grow in the future. However, we believe that explicit participation (through e.g. the Balancing Mechanism) is harder for demand-side resources due to the need to conform to a specific product definition and offer a service for sale which (e.g. NESO) must then buy (not skip), so some residual inflexibility compared to a zonal market is likely to remain.

- *Other (+£0.3 billion):* Application of all the steps above results in a residual difference of £0.3 billion with the Zonal case, due to all remaining effects. These include interactions with the hydrogen sector e.g. in the national cases, electrolysers can redispatch against hydrogen prices as well as power prices, and so redispatch volumes may not net to zero.
- *Assumed cost of capital change (-£0.4 billion):* Assuming a 1% (+100 bps) percentage point increase – considered as an optimistic case – in hurdle rates only for non-CfD supported thermal plants (reduced to +50bps for OCGT plants) reduces benefits in the Zonal case by £0.4billion.

— Zonal to Zonal Cost of Capital Sensitivity (-£10.4 billion): Assuming a more conservative 1% (+100bps) increase in hurdle rates for CfD-supported capacity in the Zonal case results in a welfare reduction of more than £10 billion, resulting in an overall disbenefit relative to BAU of -£7.1 billion. Locational prices would increase the risk in the merchant tail. While the merchant tail would typically be discounted compared to the initial CfD period[50], it can still have a very material effect on project returns. Within the merchant tail itself (the post-support period in which the plant is exposed to market prices), the additional risk depends on the view taken of the risks associated with locational prices and how these compare to risks also present in a national market, such as commodity prices, economic/political factors and technology cost evolution, as well as the risk of being exposed to locational variation in wider TNUoS tariffs.

3.2 Conclusions on welfare comparisons

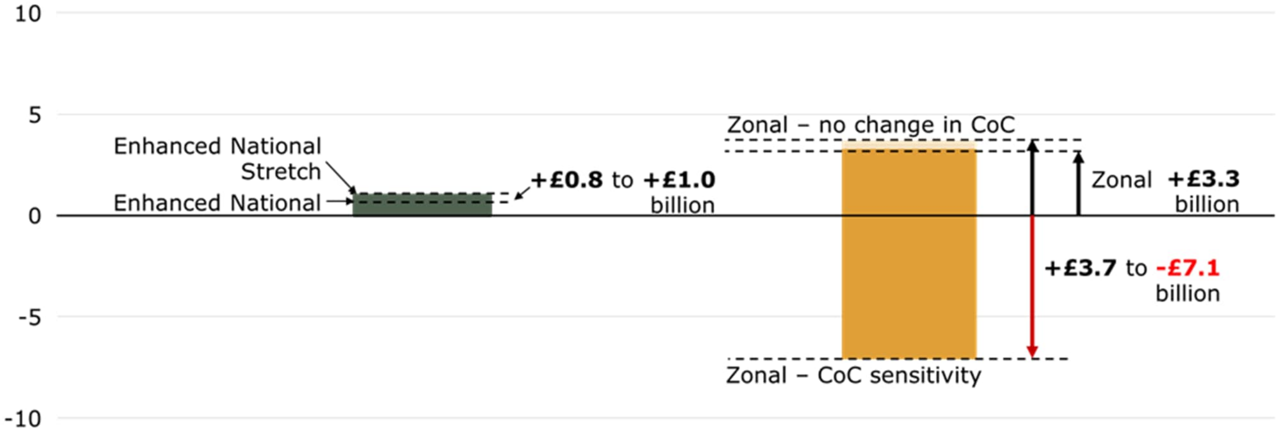
In a scenario with an appropriate level of network build, the Enhanced National market design could achieve a small overall economic welfare benefit relative to current arrangements of around £0.8 billion (NPV 2030-2050, 3.5% discount rate), or £1.0 billion in the Enhanced National Stretch case.

The potential welfare gains from operational efficiency in a zonal market are larger (although remain relatively small) at £3.7 billion. However, a zonal

[50] For example, with a 35-year asset lifetime and a 6% hurdle rate, assuming flat revenues years 16-35 would represent half the value of years 1-15, on a discounted basis.

market could also add potentially very significant new risks to investors, resulting in the only negative welfare outcome across all the cases examined (a welfare disbenefit of -£10.4 billion). The introduction of a zonal market would also bring implementation costs and a period of uncertainty while the arrangements were designed and implemented. The range of total welfare outcomes for across both the enhanced national (Enhanced National, Enhanced National Stretch) and zonal cases (Zonal – no change in CoC, Zonal and Zonal – CoC sensitivity) is summarised in Exhibit 3.4.

Exhibit 3.4 – Range of total GB economic welfare benefit, Enhanced National and Zonal cases versus National BAU (Net Present Value, £billion real 2023)



Notes: All figures are based on Net Present Value over the period 2030 to 2050, with a 3.5% discount rate. The Zonal case assumes a 100bps increase in hurdle rate for non-CfD supported thermal capacity (+50bps for OCGT). The Zonal – CoC sensitivity case assumes that in addition hurdle rates for CfD-supported capacity increase by 100bps; the Zonal – no change in CoC sensitivity removes all increases in hurdle rates from the Zonal case.

Overall, the Enhanced National or Enhanced National Stretch market designs could enable achievement of a significant share of the potential operational efficiency benefits of a zonal market, while avoiding increased risks to investment and the risk of a significantly negative welfare outcome overall. It would also cause less disruption to market participants and a more limited period of uncertainty while the new arrangements are put in place, potentially enabling some operational efficiency gains to be realised sooner. In either case, not delivering an appropriate level of network reinforcement is negative for overall welfare whether an enhanced national or zonal market design is implemented; while a zonal market could mitigate the fall in welfare from the operational inefficiency inherent in a more constrained grid, the risks to unhedged market participants would also be larger, and so the potential for further increases in cost of capital to result in a worse outcome overall would remain.

Annex A Current sources of dispatch inefficiency

AFRY has previously examined operational inefficiencies in the current scheduling and dispatch arrangements

In previous work[51], we have identified that there are several specific issues with the existing arrangements which revised arrangements should attempt to address:

i) The energy markets do not provide scheduling incentives in line with system needs and operational requirements

A major cause of re-dispatch, congestion costs and wind curtailment in today's market is the extent of transmission congestion within the GB system. This has largely resulted from rapid deployment of wind offshore and in Scotland under the policy of 'connect-and-manage', the growth in distributed generation and new interconnection (which is operating in new ways), combined with large unanticipated delays to transmission capacity build. Interconnector flows can exacerbate transmission constraints and may change position significantly or swing in direction close to real time.

Consequently, NESO is taking an increasingly large volume of actions to solve system constraints and deliver sufficient margins to ensure system security. ESO is increasingly acting as a central scheduler, with a scheduling and dispatch process designed for a residual balancing role, resulting in inefficient operational outcomes.

ii) Incomplete ESO visibility of market outcomes and limited access to some resources impacts coherence between the wholesale market and balancing

Balancing Market Units (BMUs) submit Physical Notifications (PNs) to ESO that should reflect expected level of output or consumption for each unit. At gate closure (1 hour before delivery), the PNs become 'final' – Final Physical Notifications (FPNs). These are then used for the purposes of taking any required balancing actions in the Balancing Mechanism. PNs can change up to gate closure, but accurate PNs at any given point in time are important from an ESO perspective since they inform whether any advance balancing actions are cost effective. The theory is (or at least was) that ESO has visibility of the majority of the generation resources on the system with the PNs acting as a good indication of intended production and through the BM having access to resources for manging energy balance and all other system constraints.

[51] GB scheduling and dispatch – A case for change, A report to ESO (AFRY, May 2024) https://www.neso.energy/document/318281/download

However, the growth in flexible non-BM resources and interconnector capacity in recent years has increasingly meant that the contingency decisions which ESO must take a few hours ahead of real time are increasingly being made with less complete and less accurate information, likely resulting in an increasing share of inefficient contingency actions.

Incomplete information

The increased share of distributed generation capacity, (most of) which is under no requirement to participate in the Balancing Mechanism, means that ESO does not now have complete information for contingency planning: around 35% of generation capacity is connected to the distribution system.

The limited coverage of the system by FPNs leads to uncertainty for the system operator on the demand and supply balance – the share of generation not required to submit PNs is seen indirectly and late by ESO, as a change in national demand. This results in potential for over- and under-procurement of energy and reserve through the day, and ultimately can lead to inefficient dispatch decisions.

Inaccurate information

In addition, for assets that are visible to ESO, there are increasingly large changes in position close to real time. In particular, interconnection capacity has also grown rapidly in recent years and changes in position close to real time can be very significant.

As for other market participants, trading entities on interconnectors submit nomination schedules that can evolve over time until gate closure. While the uncertainty around PNs exists for all type of BM units, the large installed capacity of interconnection, their very high ramp rates, the absence of intertemporal constraints (e.g. no minimum non-zero time) and the fact that their schedule reflects the evolution of prices in two markets means that there can be large swings very close to real time. Interconnectors are now the largest single source of changes in schedule close to real time.

This level of change in expected interconnector flows close to real time can cause operational challenges for ESO to manage as it materially changes the overall position of the system.

Limited NESO access to non-BMUs

ESO cannot currently access non-BMUs (including embedded generation and demand side response)[52]. Being able to bring more flexible resources into the same set of balancing arrangements (e.g. in the BM) would create more competition, increase liquidity and provide for more efficient dispatch solutions.

[52] GC0117 is however aimed at improving transparency and access arrangements across GB.

Limited NESO access to interconnection

Interconnectors are a key source of GB's future flexible resources, but are not fully 'dispatchable' given the link to another SO (which may have conflicting needs). Following the UK's exit from the EU on 31 January 2020, implicit capacity allocation on most GB interconnectors (except those with Ireland and Norway) came to end and has been replaced by explicit capacity allocation via a series of auctions on each interconnector[53].

a. *Limitations of pre-gate closure arrangements on interconnectors with implicit capacity allocation*

For the interconnectors without explicit capacity allocation (NSL, Moyle, and the East-West interconnector), NESO currently has few or no tools to adjust flows in the intraday timeframe, inevitably resulting in less efficient ultimate dispatch. The flows for NSL are fixed at day ahead and cannot be altered, while redispatch of Irish interconnectors is theoretically possible via trades, they tend to difficult to redispatch given Ireland tends to be subject to similar market conditions as GB (e.g. in case of change in wind patterns), meaning the relatively small Irish system may not be able to accommodate GB trades

b. *Limitations of pre-gate closure arrangements on interconnectors with explicit capacity allocation*

For interconnectors with explicit capacity allocation NESO already manages the scheduling of interconnector flows in intraday timeframes, paying interconnector registered parties to flow in the counter-market direction via ad hoc NESO auctions for required countertrade volumes and Schedule 7A agreements with interconnector registered parties; interconnector parties successful in these auctions are then required to procure the required interconnector capacity in the relevant intraday capacity auction, and to nominate the required flows. The countertrades are executed in the last available explicit capacity auction on the interconnector (occurring in the intraday timeframe) to prevent countertrade volumes being unwound by other market participants in a subsequent auction[54].

The current arrangements for NESO countertrading on explicitly allocated interconnectors offer significant flexibility to NESO to redispatch interconnector flows using a market-based approach. No formal SO-SO agreement is required for NESO countertrading, and in principle NESO can execute any volume of countertrades that the market is able to provide.

In practice the need to co-ordinate with the interconnected SOs can result in some limitations on countertrading. SO-SO coordination starts 2 days ahead of real-time to identify whether NESO countertrades are potentially going to be problematic for the SO in the interconnected market; this can result in

[53] Interconnectors which currently have explicit allocation are: IFA, IFA2, Britned, NEMO, ElecLink, Viking.

[54] As a countertrade is counter to the flow direction resulting from market prices in the interconnected markets, it has the effect of freeing-up additional capacity in the market flow direction, which other market participants will very likely utilise if they have an opportunity to do so.

limitations being applied to countertrading for particular interconnectors in particular periods. The potential to execute a large countertrade volume may therefore be limited in practice due to a late change to schedules causing system management issues for the interconnected SO.

The need to procure the required interconnector capacity in the relevant intraday capacity auction also imposes some timing constraints on the NESO ad hoc countertrade auctions, which are likely to limit the efficiency of countertrading.

Typically there are four intraday capacity auctions on each interconnector with explicit capacity allocation (the exception is ElecLink with only 2), covering blocks of delivery periods between 4 and 8 hours long (IFA2 also has a 12-hour block, and the ElecLink blocks are 10 and 14 hours). The capacity auctions generally close between 2 and 6 hours ahead of the first delivery period within the block. Once capacity has been successfully secured in the auction, flow nominations can be made between 2 hours and 1 hour ahead of the first of the remaining delivery hours associated with the block. Depending on the interconnector and the time of day, and assuming the outcomes of the NESO ad hoc auctions would need to be known 1 hour ahead of the closure of bidding, this implies that at best NESO can influence flows around 3 hours ahead of real time, and at worst around 16 hours ahead (e.g. to counter-trade flows on IFA2 1100-1200, for which the explicit capacity auction closes at 1945 the day before).

In general this reduces the flexibility of countertrading and so reduces the volume of cost-effective countertrading that can be realised.

No new adjustment to flows is possible less than 3 hours ahead of real time (and for many periods, less than 7 hours ahead), limiting the quality of information available when decisions about countertrading need to be taken, and increasing system management risk.

A further limitation which prevents the maximum economic potential from countertrading to be realised is the absence of a 24/7 trading desk for this purpose within NESO, which is a significant limitation on NESO’s ability to countertrade over a large part of the 24-hour day.

More information on realised cost-effective countertrading versus the volume of cost-effective countertrades that might be achievable is provided in Annex B.

c. Limitations of post-gate closure arrangements on interconnectors

In balancing timeframes, relying on interconnectors for cross border balancing could lead to more efficient dispatch solutions. However, following the UK exit from the EU's internal energy market, significant regulatory developments and improved SO-SO cooperation would be required to access interconnector flexibility in balancing timeframes.

iii) The current dispatch mechanism does not facilitate effective optimisation of costs and unit constraints over time

Re-dispatch cannot properly optimise across longer time periods than the 1 hour it was designed for, including unit commitment decisions for units with longer start times and the overall pattern of battery charging/discharging across the day.

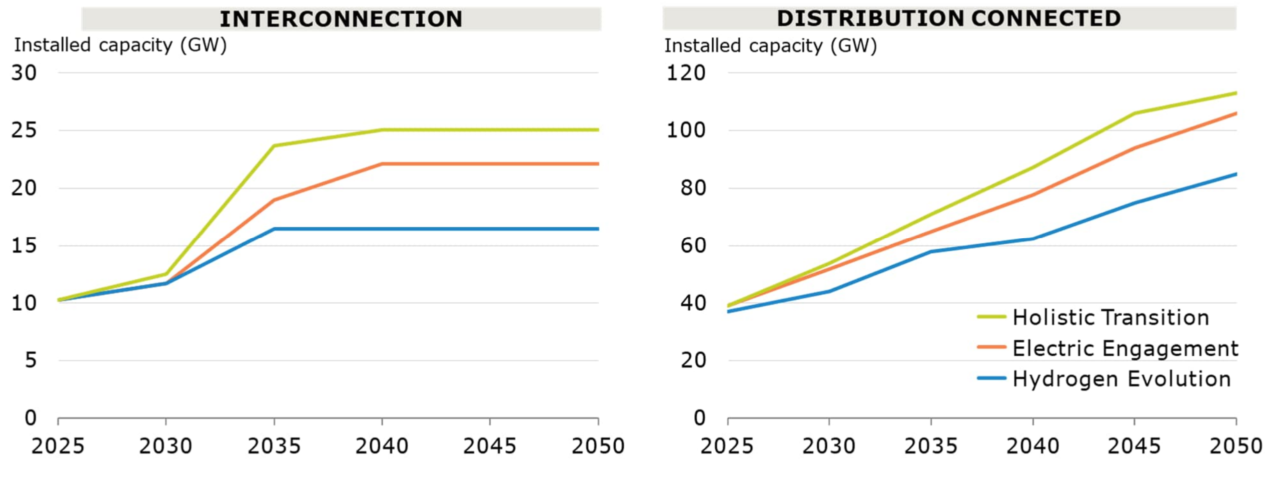
Information for pre-gate closure times is incomplete and data structures are not designed to present NESO with information on inter-temporal costs and constraints. Some early actions are taken unnecessarily due to NESO having poor information about the future behaviour of market participants and the state of storage assets, although forecast error will always be a cause of uncertainty.

The cost of any early action will not be allocated correctly (in imbalance pricing) to the period for which the action is ultimately being taken. For batteries and other storage assets, charge states are uncertain for future periods, resulting in their exclusion from contingency decisions.

Interconnector, distribution-connected and storage capacity are expected to grow in most pathways to full decarbonisation

As well as potentially being subject to inefficient scheduling and dispatch under current market arrangements, interconnector, distribution connected and storage assets are all also growing in importance as the power system moves towards rapid decarbonisation; all the current Future Energy Scenarios (FES) published by NESO project a rapid growth in capacity to 2035 and beyond (see Exhibit A.1). Any revised market arrangements, including those based on retention of a decentralised national market, must therefore incorporate features which better enable optimal dispatch of these asset types.

Exhibit A.1 – Installed capacity of interconnector and distribution connected capacity in the FES 2024 Pathways



Note: Distribution-connected capacity chart excludes storage.

Annex B Market-design specific modelling assumptions

To quantify the potential impacts of the Enhanced National and Enhanced National Stretch market designs, where possible we have developed quantitative assumptions for the market design elements.

The seven market design elements quantified are shown in Exhibit B.1 below, indicated by red boxes.

The three market design elements not quantified mostly relate to various forms of improved information sharing, and improved utilisation of residual non-BMU capacity through various routes. Although not quantified, they complement the other elements and support a coherent design for an Enhanced National or Enhanced National Stretch market design.

Exhibit B.1 – Market design elements quantified in the Enhanced National and Enhanced National Stretch cases

Building block		Enhanced National	Enhanced National Stretch
Management of interconnectors	Pre-gate closure: Expanded NESO countertrading on interconnectors	1 Improved NESO access to interconnector assets ahead of gate closure through more frequent explicit capacity auctions on all interconnectors and the introduction by NESO of 24/7 trading	9 Expanded NESO potential to secure earlier and more cost-effective interconnector countertrades without the possibility of subsequent unwinding by other market participants
	Post-gate closure: Expanded NESO use of interconnectors in balancing timeframes	2 Improved NESO access to interconnector assets post gate closure through expansion of SO-SO trading	10 Improved NESO access to interconnector assets post gate closure through improved cross-border balancing via a bilateral cross-border balancing platform (or via direct nomination between SOs)
Management of small-scale assets	Improved FPNs	3 Increased NESO visibility of BMUs through incentives to improve accuracy of Final Physical Notifications (FPNs)	
	Improved NESO optimisation of small-scale BMU assets	4 Improved NESO forecasting tools and optimisation processes to improve NESO access to small-scale BMU assets in balancing and redispatch	
	Lowering of BMU threshold to 10MW	5 Improved NESO visibility of and access to a larger number of small-scale assets through lowering of the capacity threshold for mandatory participation in the Balancing Mechanism to 10MW for new assets (but not retrospectively for existing non-BMU assets)	
	Improved NESO visibility and access to non-BMU assets	6 Improved NESO visibility and access to remaining non-BMU distribution-connected assets through: improved information provision to the SO in short-term planning and operational timeframes; extension of arrangements for NESO access to non-BMU resources (e.g. constraints management markets); and reduced barriers to voluntary participation in the Balancing Mechanism and other balancing services	
Management of storage assets	Improved information sharing between NESO and storage assets	7 Improved information sharing between NESO and storage assets on system requirements and dispatch expectations (e.g. unit commitment, profile of battery charge and discharge) to support more effective NESO within-day optimisation over extended periods.	
	Improved NESO market arrangements for optimisation of storage assets	8 Improved management of intertemporal issues through the capability for NESO to 'commit' usable energy from storage assets ahead of gate closure	

Quantified market elements

The assumptions for each of the quantified market design elements are set out in more detail on the pages that follow

B.1 Management of interconnectors pre-gate closure – expanded NESO counter-trading

B.1.1 Current arrangements

Although interconnectors are registered as Balancing Mechanism Units (BMUs), NESO does not redispatch them in the Balancing Mechanism. Instead, redispatch occurs pre-gate closure via NESO trading with interconnector parties (post-gate closure redispatch via separate SO-SO arrangements is discussed below).

Pre-gate closure and post-day ahead for a given settlement period, NESO has an initial view (based on IPNs and an initial Security Constrained Economic Dispatch run) of the state of energy imbalance, network and other system constraints, and the costs of resolving these through bids and offers in the Balancing Mechanism. One of the options available to NESO to manage anticipated system constraints is to alter the scheduled flow on one or more of the interconnectors. For interconnectors which currently have explicit capacity allocation (i.e. all except those with Ireland and Norway, which have implicitly allocated capacity based on a market-coupling algorithm), once the day-ahead interconnector capacity auctions and resulting flows nominations have been made, NESO can start to run auctions for potentially desired reverse flow volumes (known as countertrading). These auctions are ad hoc and there can be several over the intraday period. Market participants able to trade on interconnectors bid into these auctions to provide a reverse flow volume. NESO is not required to procure the total redispatch volume offered via the auction; instead it will compare bids with the cost of the anticipated cheapest alternative action in the Balancing Mechanism and accept bids up to that level.

If bidders are successful in the auction, they are then required to contract with a cross-border counterparty to flow the required volume, participate in the intraday capacity auctions which occur on each interconnector with explicitly allocated capacity to reserve the required capacity, and nominate the required flow. As a NESO countertrade reduces the flow volume in the direction that would be expected commercially based on the price differential between the interconnected markets, creating additional capacity in this direction, it is very likely that other market participants would seek to do further trades in this direction and thus unwind the countertrade volume. For this reason NESO has to time its countertrades so that they are given effect in the last explicit capacity auction on each interconnector i.e. in the intraday timeframe.

The volume of NESO interconnector countertrading is significant; since the arrangements were introduced in December 2020, over the period 2021 to 2023 NESO has secured additional annual volumes of imports of between 0.4TWh (2021) and 3.2TWh (2022), and additional annual volumes of exports of between 0.8TWh (2022) and 2.8TWh (2021). In particular months interconnector countertrades have been utilised particularly heavily by NESO to manage the system; in July 2022 NESO interconnector buy countertrades represented 60% of overall positive balancing volumes (i.e. Bid Offer Acceptances (BOAs) + trades), while in August 2021 sell countertrades represented 44% of overall negative balancing volumes. At least for interconnectors with the current explicitly allocated capacity arrangements, this illustrates that interconnectors already have greater flexibility to be redispatched than is commonly assumed.

B.1.2 Enhanced National – assumptions for additional countertrading potential

Building block		Enhanced National
Management of interconnectors	**Pre-gate closure: Expanded NESO countertrading on interconnectors**	1 Improved NESO access to interconnector assets ahead of gate closure through arrangements for all interconnectors to provide a final explicit intraday capacity auction 2-3 hours ahead of real time to facilitate expanded NESO countertrading

B.1.2.1 Enhanced National potential - buy trades on interconnectors with explicitly allocated capacity

Our analysis of Balancing Service Adjustment Data (BSAD) suggests that there is greater potential for cost-effective NESO countertrading of interconnection.

We have identified additional potential for buy trade and sell trades separately. In both cases, by looking at historical data we have identified the typical cost of a NESO interconnector countertrade with the cost of the alternative bid or offer acceptance in the Balancing Mechanism.

Buy trades by NESO on the southern interconnectors (i.e. those with explicit capacity allocation connecting to France, Belgium, the Netherlands and Denmark[55]) typically occur on windy days when one of the network boundaries between northern Scotland and southern England is constrained, resulting in NESO accepting bids to turn down wind in Scotland, and accepting offers to turn-up from thermal plants south of the constraint. Reducing exports from (or possibly increasing imports to) southern England through NESO buy countertrades can be more cost-effective than accepting additional thermal plant offers in the BM.

For example, on 28th January 2024, it appears there was an opportunity to use further buy trades on interconnectors to solve transmission constraints.

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[55] IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

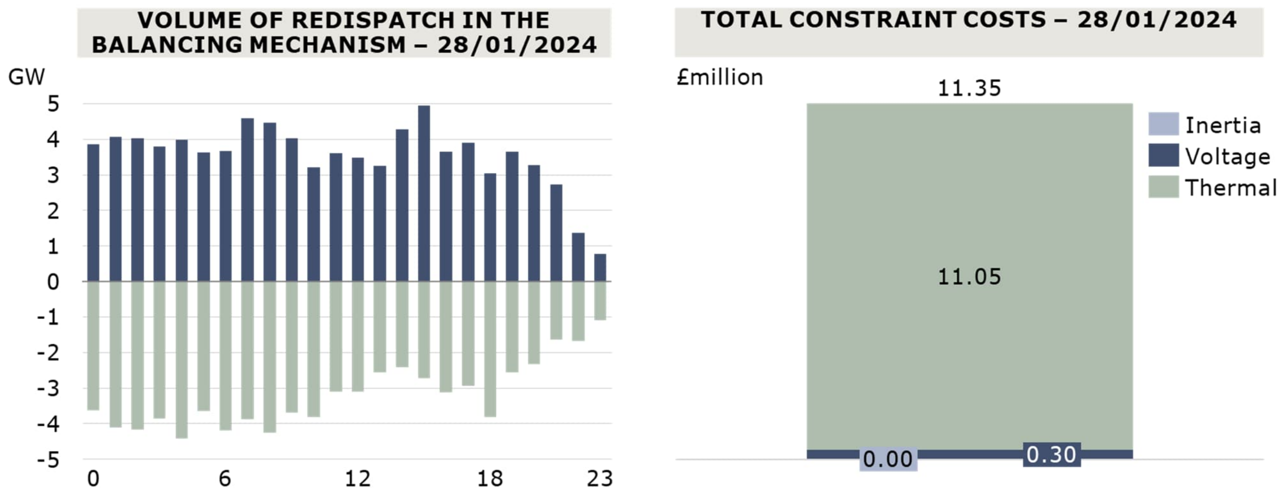
On 28th January 2024, high wind generation led to transmission constraints. Across the day ~4GW of wind was bid down in the BM, and the equivalent volume offered up in England (mainly from gas generation in the south of England and the Midlands).

Whether additional interconnector imports on the southern interconnectors could have replaced some of the thermal capacity being offered depends on the reason for the offer acceptances. Inertia constraints can only be solved with synchronous plants (generally thermal plants), and cannot be substituted with volumes from non-synchronous sources such as interconnectors. However, to replace generation volumes lost through bid-off wind, both synchronous and non-synchronous sources can be offered-up. Periods with high wind generation and low demand can tend to result in both transmission constraints and inertia constraints appearing, although as NESO flags the reasons for BOAs, it is possible to distinguish the costs associated with each type of constraint.

For 28th January 2024, based on published daily constraints cost breakdown, transmission constraints were the primary reason for redispatch on that day: thermal constraint costs for the day were £11.05 million, while the costs of the inertia and voltage constraints were low at £0.3 million.

Total redispatch volumes over the day and total constraint costs for 28th January 2024 are shown in Exhibit B.2.

Exhibit B.2 – Volume of redispatch in the Balancing Mechanism and total net interconnector imports on the South Coast interconnectors on 28th January 2024



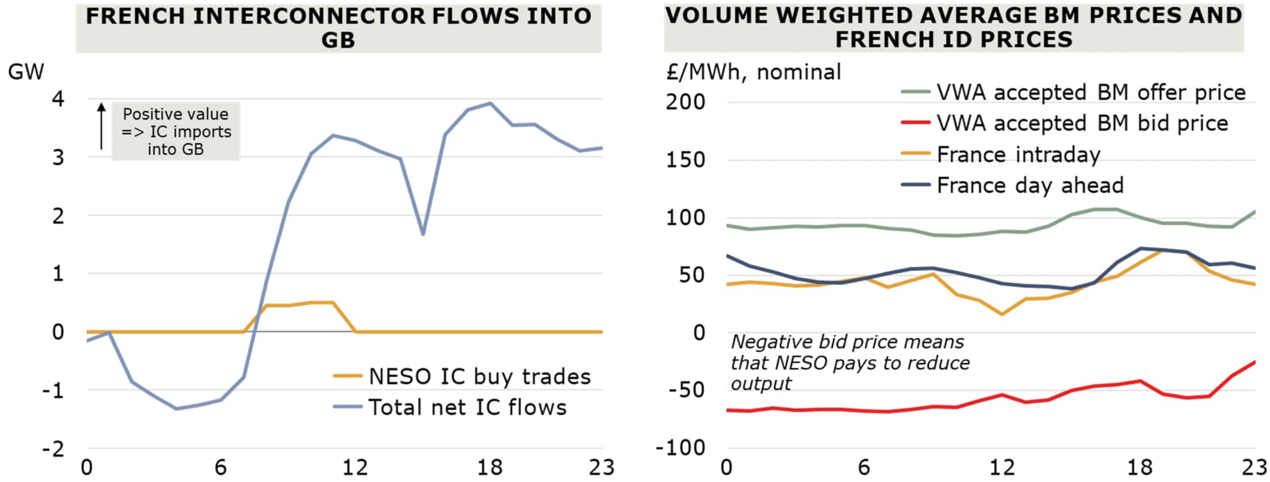
Sources: NESO, AFRY analysis

In addition to whether the state of flows an interconnector makes a countertrade possible, NESO has to consider the cost of the countertrade versus possible alternative actions; NESO is under a licence condition to take balancing actions based on a merit order of least cost.

As illustrated in Exhibit B.3, early in the morning the French interconnectors were exporting from GB, adding to the thermal turn-up requirement in the

South of England, rather than reducing it. In addition, over this period, the intraday price in France was consistently lower than the average accepted offer price in the BM. The French intraday discount to the average accepted offer price between midnight and 6am ranged between €46 and €52/MWh. It appears that there was additional potential to organise buy interconnector trades, compared to the trades actually done on that day (a limited volume of around 500MW between 8am and 11am).

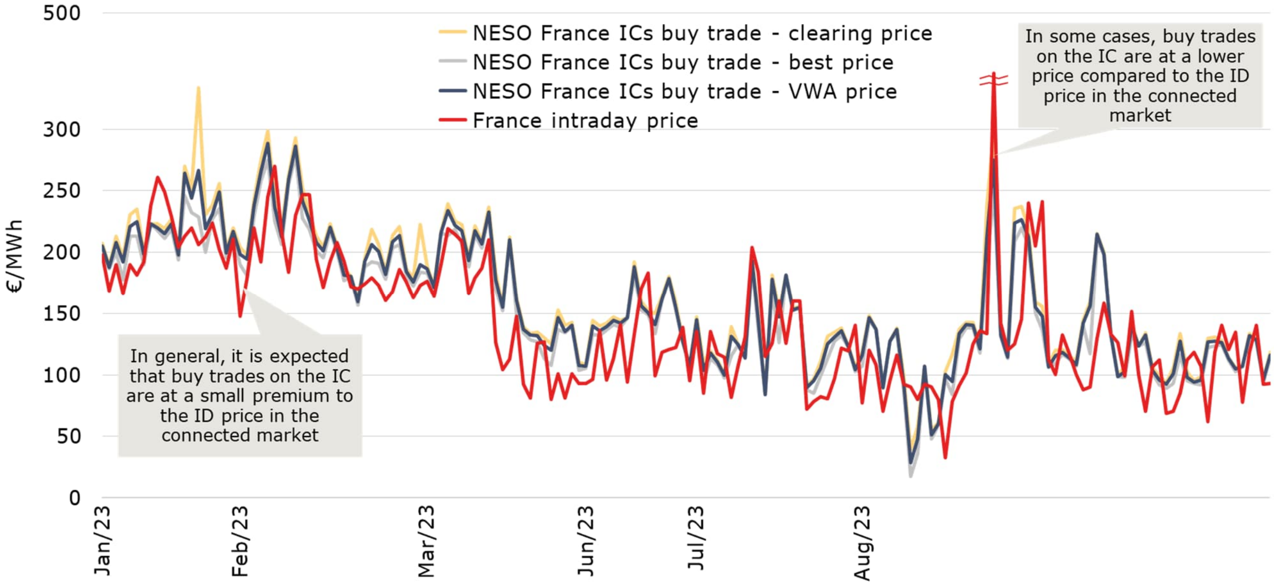
Exhibit B.3 – Net French interconnector flows, NESO buy trades, volume-weighted BM accepted prices and French intraday prices on 28th January 2024



Sources: NESO, EPEX

To examine the additional cost-effective potential for NESO interconnector buy trades versus alternative Balancing Mechanism actions, we have identified the typical cost of interconnector buy trades historically. As the trade is essentially procuring power from a generator on the continent intraday, and the value of interconnector capacity in the reverse flow direction is low, it might be expected that in a liquid market the cost of the trade would be close to the intraday price on the continent. A comparison of the cost of NESO buy trades on the French interconnectors with French intraday prices is shown in Exhibit B.4. Across buy trades over the period 2022 to 2024, the average premium to the French intraday price has been around €20/MWh. A comparison of volume weighted buy trades over all the south coast interconnectors with volume-weighted average intraday prices across the interconnected countries yields a similar premium.

Exhibit B.4 – Cost of NESO buy trades on the interconnectors with France, compared with the French intraday price



Sources: NESO, EPEX

Applying this approach based on the difference between accepted offer prices in the Balancing Mechanism and intraday prices on the continent, it is possible to identify volumes of potential additional cost-effective interconnector buy trades to resolve transmission constraints on all of the southern interconnectors.

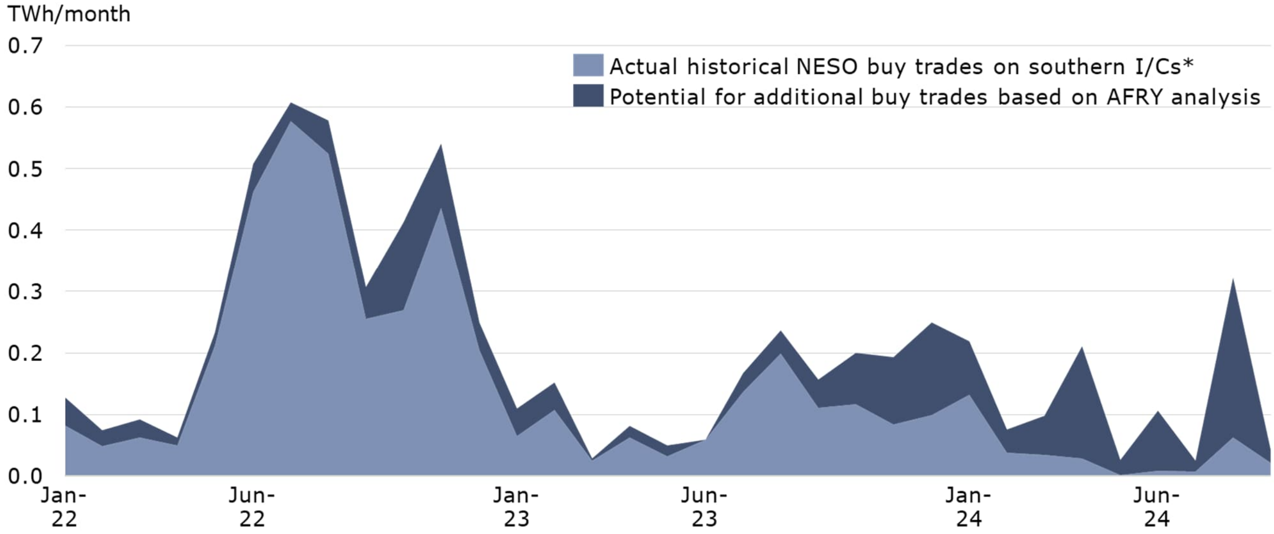
We have identified the periods and volumes of potential further cost-effective southern interconnector buy trades to solve transmission constraints using the following approach. To identify a further volume achievable in the Enhanced National based on the various constraints NESO may face in practice, this additional potential volume is based on:

- hours when the BM volume weighted average accepted offer price is higher than the blended FR/BEL/NL intraday price, plus a €20/MWh premium
- days when transmission constraints costs are higher than £2m
- days when inertia constraint costs are lower than £250k (to not consider BM actions to solve both inertia and thermal constraints)
- hours when NESO traded less than 2000MW (of buy trades)
- hours when GB is a net exporter on the FR, BEL, NL and DK interconnectors
- the maximum potential volume in each hour is capped by the lowest of:
  - the remaining import capacity on the FR, BEL, NL and DK interconnectors; or
  - 80% of the accepted offer volume in that hour (to reflect the fact that some BM actions are for localised needs and cannot be replaced by I/C buy trades); or

— 4000MW (to reflect the fact that it appears to be rare for NESO to fully reverse flows on interconnectors via trades)

The resulting additional potential buy trade volume compared with the actual volume is shown in Exhibit B.5. The total potential additional volumes over 2022 and 2023 were around 0.6TWh/year, with higher potential in the first 9 months of 2024 (0.8TWh).

Exhibit B.5 – Actual and potential additional monthly buy trade volumes identified on southern I/Cs



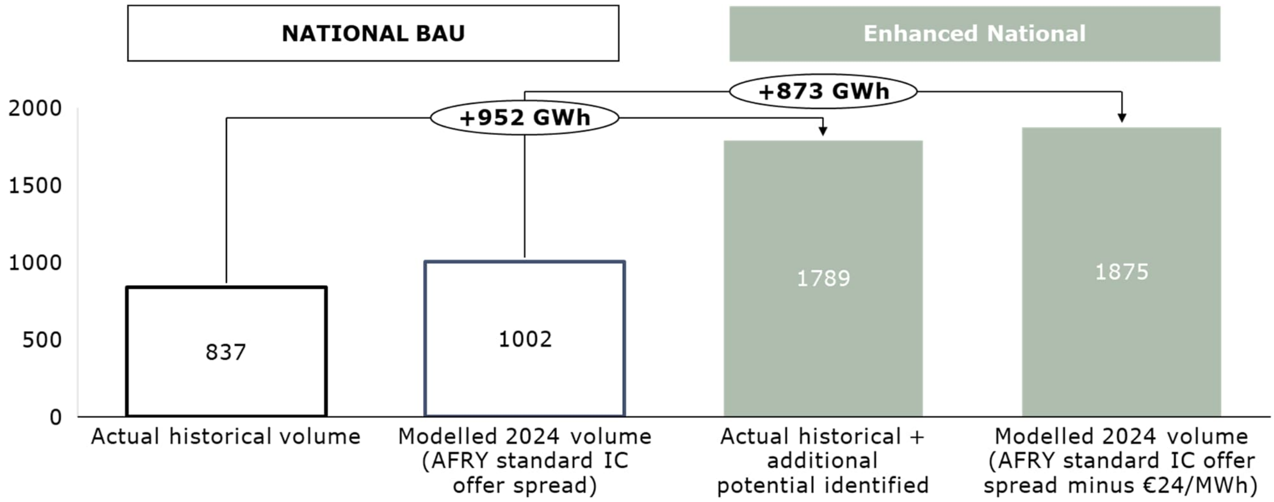
Sources: NESO, AFRY
* Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

Within AFRY's modelling of the Balancing Mechanism (which includes NESO scheduling actions strictly taken outside the BM), the degree of interconnector flexibility and hence redispatch volume is largely set by the assumed bid/offer spreads applied to interconnectors – large values (wide spreads) result in fewer IC redispatch actions being taken and lower redispatch volumes, with the converse being true for lower values (narrower spreads).

To derive offer spread assumptions that reflect the additional achievable potential in an Enhanced National case, we have calibrated these against the potential volumes using model runs to derive a suitable 2024 modelled year, to match the current additional potential we have identified (based on historical data between October 2023 and September 2024, reflecting the closest historical match to a 2024 modelled year available at the time of the analysis).

The result of this calibration process is shown in Exhibit B.6. The additional potential we have identified amounts to 952 GWh per annum, and we find that reducing the standard offer spread for the southern interconnectors by €24/MWh increases the modelled volume of redispatch in 2024 by 873GWh, which we have adopted as a reasonably good match.

Exhibit B.6 – Historical, potential and modelled IC buy trade volumes on the Southern interconnectors (GWh/annum)



Notes: The historical volume of 837GWh reflects an annual volume based on October 2023 to September 2024. Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

B.1.2.2 Enhanced National potential - sell trades on interconnectors with explicitly allocated capacity

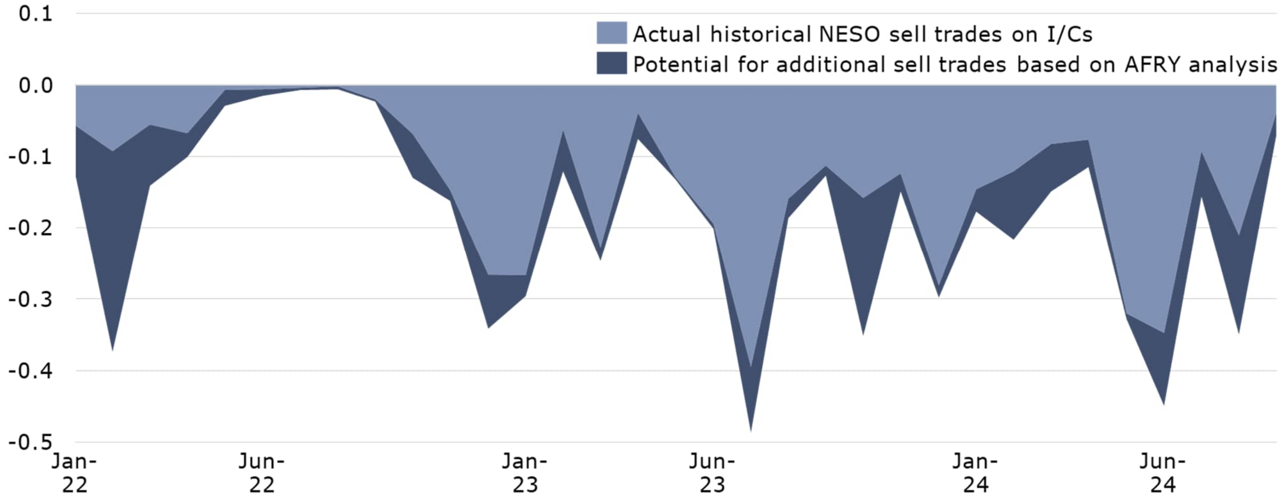
We have identified the periods and volumes of potential further cost-effective southern interconnector sell trades to solve inertia constraints using the following approach. To identify a further volume achievable in the Enhanced National based on the various constraints NESO may face in practice, this additional potential volume is based on:

- Hours when the BM volume weighted average accepted bid price is lower than the blended FR/BEL/NL intraday price - €15/MWh discount (to find when it is more profitable to sell on the interconnector than receiving payment for accepted bids on the BM)
- Days when inertia costs are higher than £0.5m
- Hours when NESO traded less than 3000MW
- Hours when GB is a net importer on the FR, BEL, NL and DK interconnectors
- The maximum potential volume in each hour is capped by the lowest of:
  - the remaining import capacity on the FR, BEL, NL and DK interconnectors
  - 80% of the accepted bid volume in that hour (to reflect the fact that some BM actions are for localised needs and cannot be replaced by I/C sell trades)
  - 4000MW (to reflect the fact that it appears to be rare for NESO to fully reverse flows on I/Cs via trades)

— hours when the BM volume weighted average accepted offer price is higher than the blended FR/BEL/NL intraday price, plus a €20/MWh premium

The resulting additional potential buy trade volume compared with the actual volume is shown in Exhibit B.7.

Exhibit B.7 – Actual and potential additional monthly sell trade volumes identified on southern I/Cs (TWh/month)



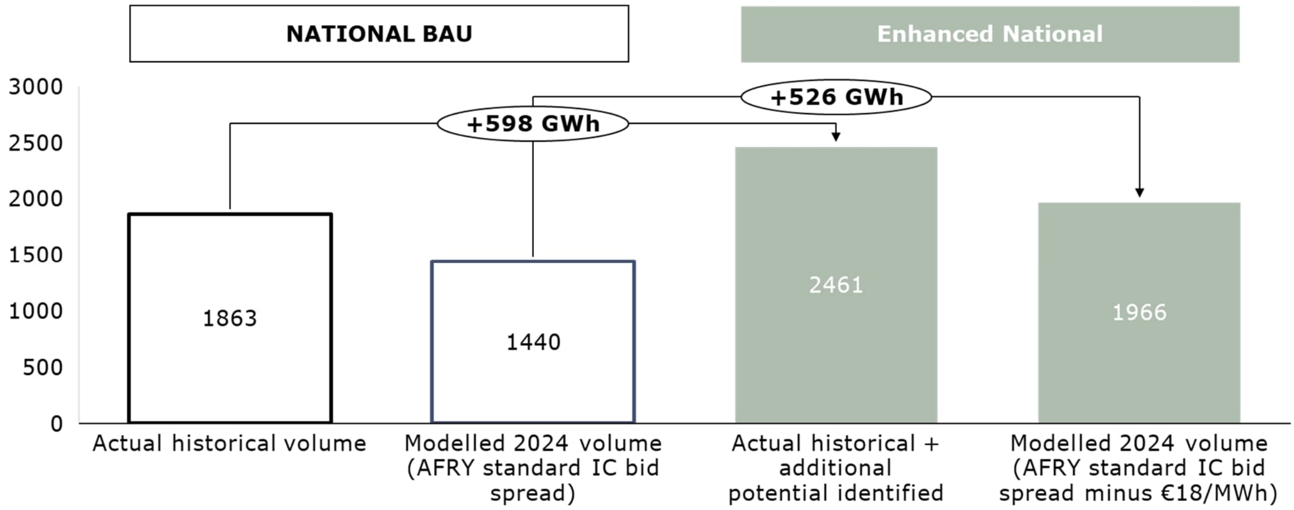
Sources: NESO, AFRY
* Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

Based on our estimate of the volumes of potential further interconnector sell countertrades on days with high inertia costs, we calibrated our BID3 redispatch model using the 2024 modelled year.

We lowered the bid spread we assume on interconnector redispatch in our standard modelling, in order to obtain similar change in overall sell trade volumes reflecting the identified higher interconnector trade potential.

The result that is lowering our I/C bid spread by €18/MWh (real 2023) compared to our standard modelling assumptions results in a change in modelled interconnector sell trade volumes in line with the additional potential identified (see Exhibit B.8).

Exhibit B.8 – Historical, potential and modelled IC sell trade volumes on the Southern interconnectors (GWh/annum)



Notes: The historical volume of 1863 GWh reflects an annual volume based on October 2023 to September 2024. Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

B.1.2.3 Enhanced National potential - buy trades on interconnectors with implicitly allocated capacity

The main focus of the redispatch modelling in this study is to resolve transmission constraints. It is expected that interconnectors with implicitly allocated capacity located in the north of the country (i.e. the interconnectors with Ireland and Norway) would be used extremely rarely for buy trades to solve transmission constraints. The need is generally to limit generation in the north to resolve north-south export constraints, and more imports on northern interconnectors would only exacerbate this type of transmission constraint.

As a result, simple assumptions on offer spreads have been made for interconnectors with implicitly allocated capacity in the Enhanced National case. For the interconnector with Norway, NESO countertrading is not possible at present. However, we assume that in the Enhanced National, some countertrading would be feasible, through either:

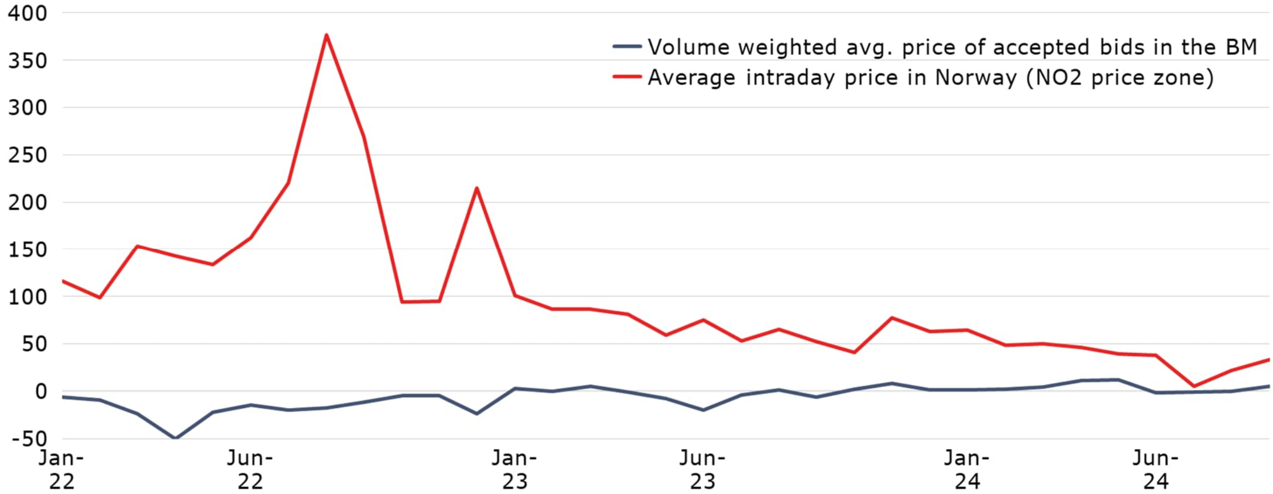
- the introduction of an explicit intraday interconnector auction for this purpose (as was the case for GB-France interconnectors before the UK left the EU Internal Energy Market in 2021); or
- the introduction of an explicit capacity product for use within the coupling algorithm.

An explicit interconnector capacity product could be implemented in the market coupling algorithm. Interconnector capacity would be reserved by the TSO defining an interconnector reserve product (effectively an interconnector capacity option).

The European price coupling algorithm seeks to maximise the sum of the economic surplus from the day ahead schedule plus the economic surplus from the exchange of balancing capacity between bidding zones. Accordingly, NESO could define a cross-border balancing capacity requirement at a given price (based on its expected requirement for interconnector repositioning to solve transmission constraints), which would then be included as an additional constraint in the market coupling algorithm.

To reflect the potential for redispatch on implicit interconnectors, the assumed offer spread on implicit interconnectors is the AFRY standard assumption for explicit interconnectors i.e. is set to be same as for interconnectors with explicitly allocated capacity in the National BAU case.

Exhibit B.9 – Monthly volume-weighted average prices of accepted bids in the BM versus average intraday NO2 prices (€/MWh)



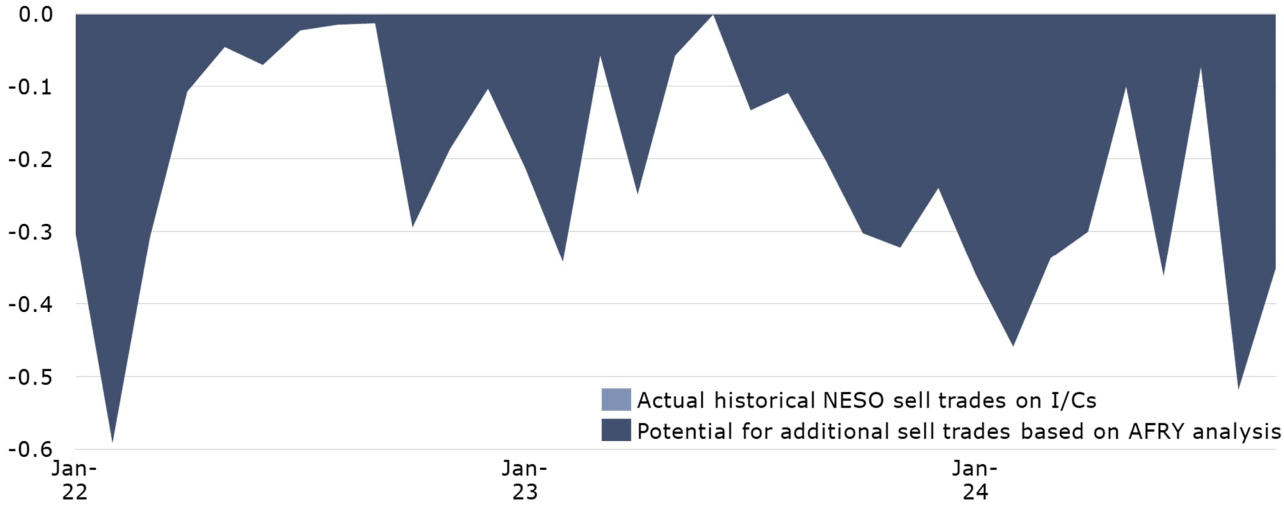
Sources: NESO, Nord Pool, AFRY analysis

We have calculated periods and volumes of potential I/C sell trades on the Norwegian interconnector to help to solve transmission constraints (instead of accepting bids in the BM) using the following approach. We have only considered:

- Hours when the BM volume weighted average accepted bid price is lower than the NO2 intraday price - €15/MWh discount (to find when it is more profitable to sell on IC than receiving payment for an accepted bid)
- Days when transmission constraints costs are higher than £2m
- Hours when GB is a net importer on the NSL interconnector
- The maximum potential volume in each hour is capped by the lowest of:
  - the remaining import capacity on the NSL interconnector
  - 80% of the accepted bid volume in that hour (to reflect the fact that some BM actions are for localised needs and cannot be replaced by I/C sell trades)
  - 1120MW (to reflect the fact that it appears to be rare for NESO to fully reverse flows on I/Cs via trades)

The resulting additional potential buy trade volume compared with the actual volume is shown in Exhibit B.10.

Exhibit B.10 – Potential monthly sell trade volume identified on NSL (TWh/month)

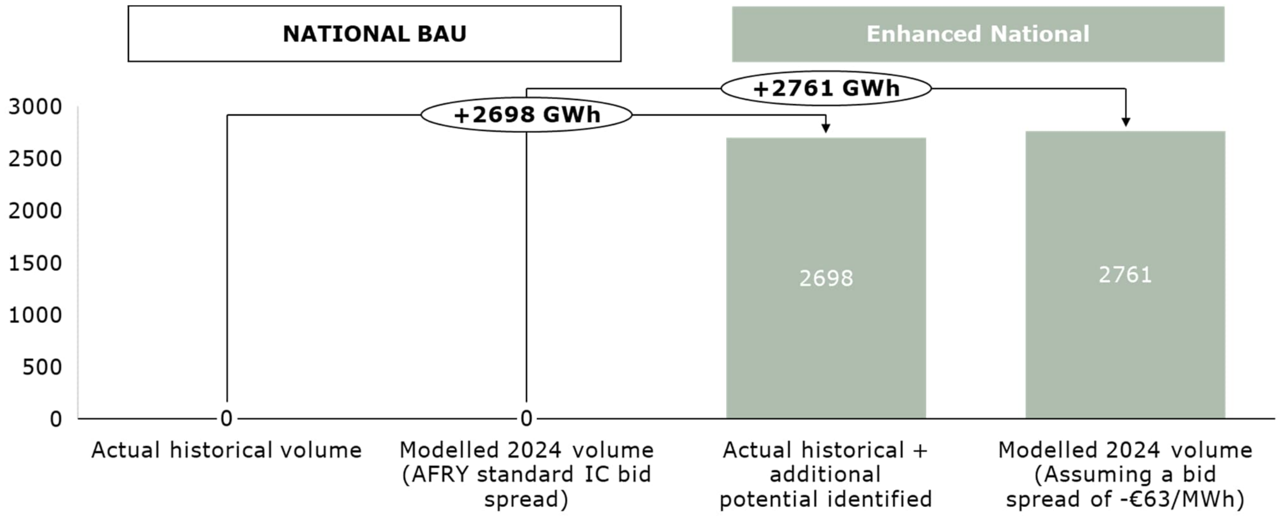


Sources: AFRY

Based on our estimate of the volumes of potential sell trades on NSL, we calibrated our BID3 redispatch model using the 2024 modelled year, on the currently theoretical assumption that NESO countertrading actions are possible.

As illustrated in Exhibit B.11, to achieve the identified NSL sell trade potential, we found that the required bid spread would be -€63/MWh (real 2023).

Exhibit B.11 – Potential and modelled IC sell trade volumes on the NSL interconnector (GWh/annum)



B.1.3 Enhanced National Stretch – assumptions for additional countertrading potential

Building block		Enhanced National Stretch
Management of interconnectors	Pre-gate closure: Expanded NESO countertrading on interconnectors	9 Expanded NESO potential to secure earlier and more cost-effective interconnector countertrades without the possibility of subsequent unwinding by other market participants

In the Enhanced National Stretch case, we go beyond the potential for interconnector countertrading that may be possible based on the current approach of trading in a final intraday capacity auction on interconnectors (although additionally with introduction of these on the interconnectors that currently have implicit arrangements), and envisage further enhancements to market arrangements for interconnector countertrading based on the ability to lock in trades made other than in a final intraday auction, either through novel use of NTC restrictions, or through a new capacity product capable of being offered, tradeable on interconnectors with implicit capacity allocation. The Enhanced National Stretch arrangements would enable NESO to secure earlier (and therefore potentially larger) countertrade volumes, at potentially lower cost.

B.1.3.1 Enhanced National Stretch potential - buy trades on interconnectors with explicitly allocated capacity

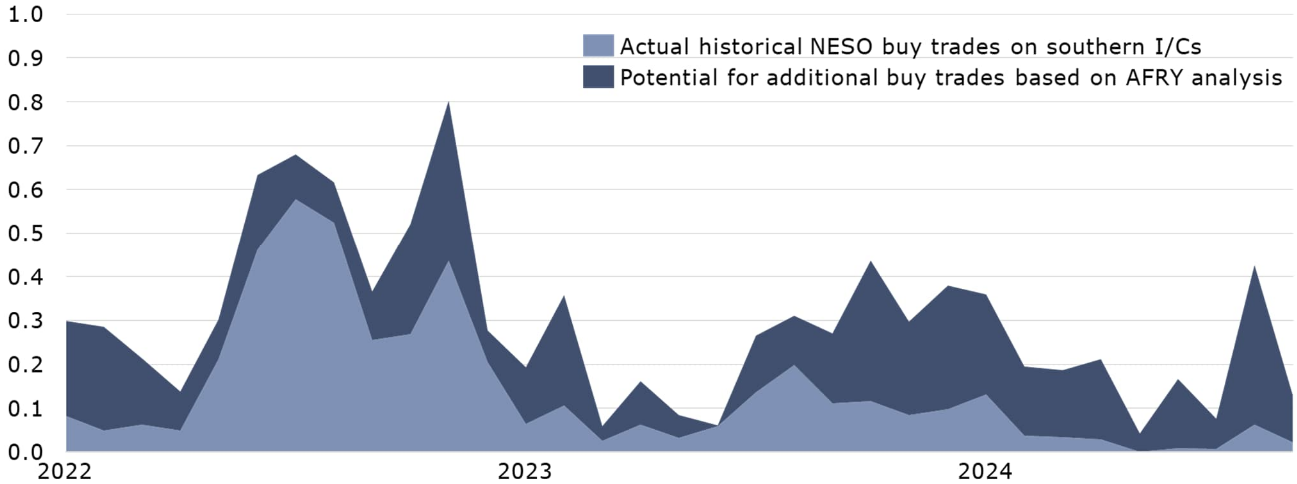
In the Enhanced National Stretch case we have identified the periods and volumes of potential further cost-effective southern interconnector buy trades to solve transmission constraints using the following approach. Compared to historical volumes, this additional potential volume is based on:

- Hours when the BM volume weighted average accepted offer price is higher than the blended FR/BEL/NL intraday price +€15/MWh premium (compared to €20/MWh premium in the Enhanced National case, to reflect the fact that better prices can be obtained with the ability to trade at more timeframes)
- Days when transmission constraints costs are higher than £1.5m (vs. £2m in the Enhanced National case)
- Days when inertia constraint costs are lower than £250k (to not consider BM actions to solve both inertia and thermal constraints)
- Hours when NESO traded less than 3000MW on ICs (buy trades)
- Hours when GB is importing less than 1500MW on the FR, BEL, NL and DK interconnectors (instead of GB being a net exporter in the Enhanced National case)
- The maximum potential volume in each hour is capped by the lowest of:
  - the remaining import capacity on the FR, BEL, NL and DK interconnectors

- 80% of the accepted offer volume in that hour (to reflect the fact that some BM actions are for localised needs and cannot be replaced by I/C buy trades)
- 5000MW (vs. 4000MW in the Enhanced National, to reflect the increase potential to fully reverse flows on I/Cs by executing trades earlier)

The resulting additional potential buy trade volume compared with the actual volume is shown in Exhibit B.12.

Exhibit B.12 – Actual and potential additional monthly buy trade volumes identified on southern I/Cs

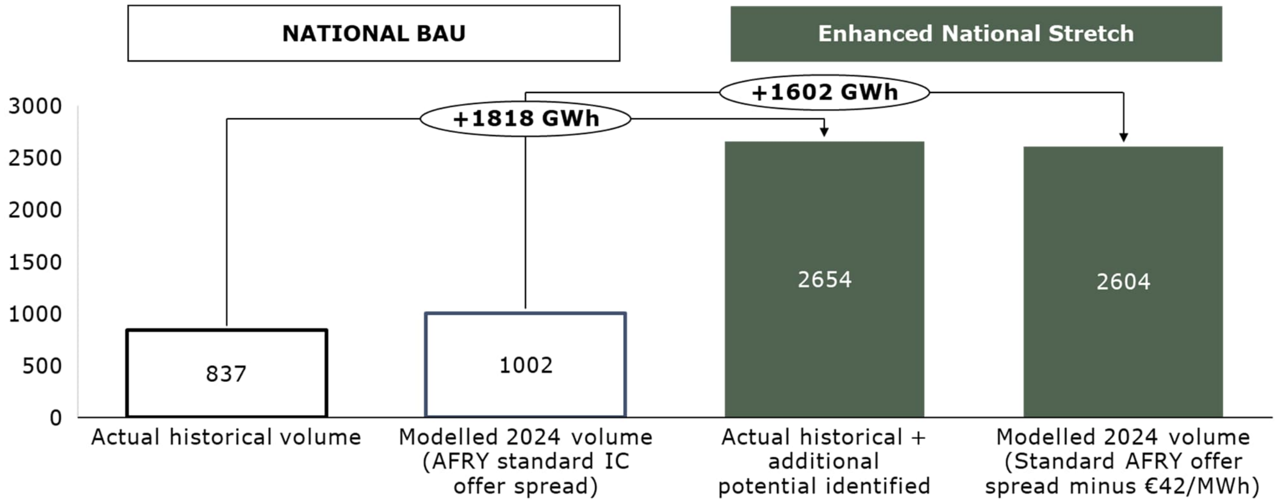


Sources: NESO, AFRY
* Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

To derive offer spreads assumptions that reflect the additional achievable potential in an Enhanced National Stretch case, we have calibrated these against the potential volumes in model runs to derive a suitable value using a 2024 modelled year, to match the current additional potential we have identified (between October 2023 and September 2024, reflecting the closest historical match to a 2024 modelled year).

The result of this calibration process is shown in Exhibit B.13. The additional potential we have identified amounts to 1818 GWh per annum, and we find that reducing the standard offer spread for the southern interconnectors by €42/MWh increases the modelled volume of redispatch in 2024 by 1602 GWh, which we have adopted as a reasonably good match.

Exhibit B.13 – Historical, potential and modelled IC buy trade volumes on the Southern interconnectors (GWh/annum)



Notes: The historical volume of 837GWh reflects an annual volume based on October 2023 to September 2024. Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

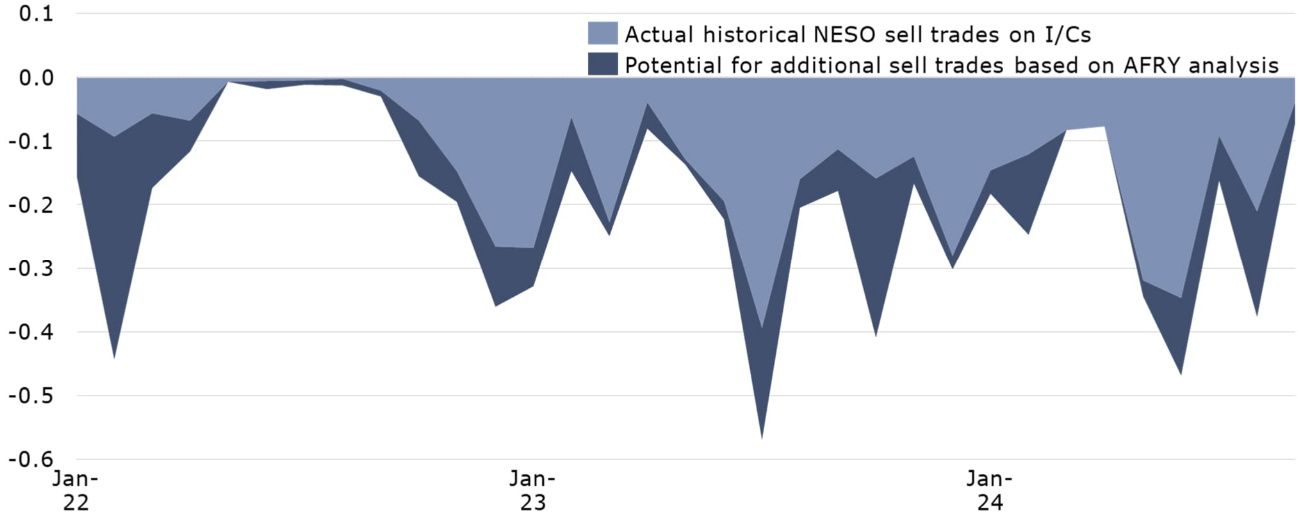
B.1.3.2 Enhanced National Stretch potential - sell trades on interconnectors with explicitly allocated capacity

In the Enhanced National Stretch case we have identified the periods and volumes of potential further cost-effective southern interconnector sell trades to solve inertia constraints using the following approach. This additional potential volume is based on:

- Hours when the BM volume weighted average accepted bid price is lower than the blended FR/BEL/NL intraday price - 10€/MWh discount (to find when it is more profitable to sell on the IC than receiving payment for accepted bids in the BM)
- Days when inertia costs are higher than £0.5m
- Hours when NESO traded less than 3000MW
- Hours when GB exports less than 1’500MW on the FR, BEL, NL and DK interconnectors
- The maximum potential volume in each hour is capped by the lowest of:
  - the remaining import capacity on the FR, BEL, NL and DK interconnectors
  - 80% of the accepted bid volume in that hour (to reflect the fact that some BM actions are for localised needs and cannot be replaced by I/C sell trades)
  - 4000MW (to reflect the fact that it appears to be rare for NESO to fully reverse flows on I/Cs via trades)

The resulting additional potential buy trade volume compared with the actual volume is shown in Exhibit B.14.

Exhibit B.14 – Actual and potential additional monthly sell trade volumes identified on southern I/Cs (TWh/month)



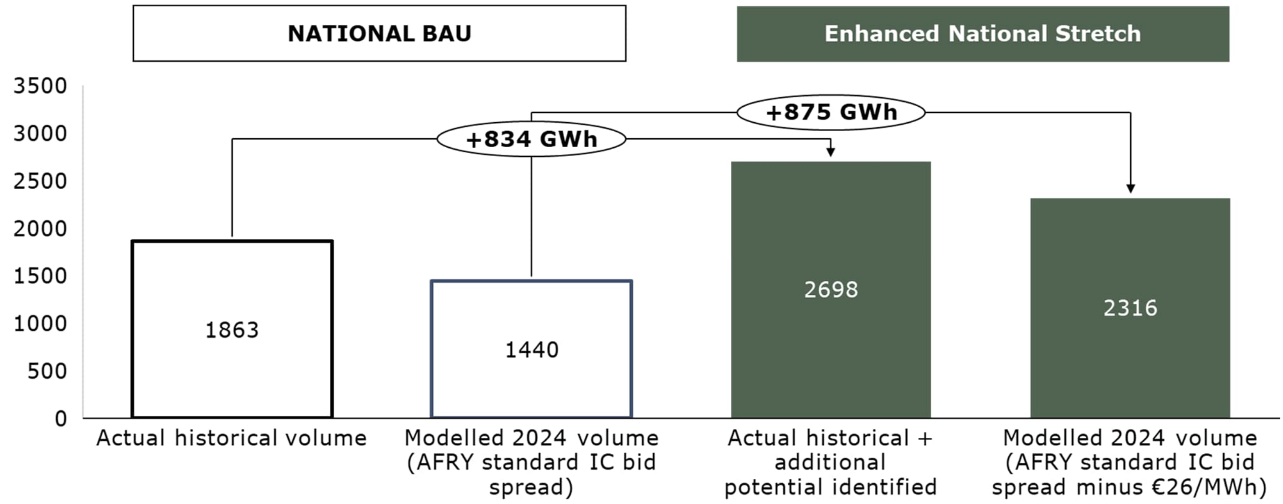
Sources: NESO, AFRY
* Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

Based on our estimate of the volumes of potential further interconnector sell countertrades on days with high inertia costs in the Enhanced National Stretch case, we calibrated our BID3 redispatch model using the 2024 modelled year.

We lowered the bid spread we assume on interconnector redispatch in our standard modelling, in order to obtain similar change in overall sell trade volumes reflecting the identified higher interconnector trade potential.

The result that is lowering our I/C bid spread by €26/MWh (real 2023) compared to our standard modelling assumptions results in a change in modelled interconnector sell trade volumes in line with the additional potential identified (see Exhibit B.15).

Exhibit B.15 – Historical, potential and modelled IC sell trade volumes on the Southern interconnectors (GWh/annum)



Notes: The historical volume of 1863 GWh reflects an annual volume based on October 2023 to September 2024. Southern ICs comprise IFA, IFA2, ElecLink, NEMO, BritNed and Viking Link.

B.1.3.3 Enhanced National Stretch potential - buy trades on interconnectors with implicitly allocated capacity

As described in B.1.2.3, it is expected that northern interconnectors with implicitly allocated capacity (interconnectors with Ireland and Norway) would be used extremely rarely for buy trades to solve transmission constraints. This is because more imports on northern interconnectors would only tend to exacerbate north-south export transmission constraints.

We therefore take simple assumptions on offer spreads for interconnectors with implicitly allocated capacity in the Enhanced National Stretch case. We assume that in the Enhanced National Stretch case, the offer spread on implicit interconnectors is the AFRY standard assumption for explicit interconnectors minus €42/MWh, which is the assumption for explicit interconnectors in the Enhanced National case.

B.1.3.4 Enhanced National Stretch potential - sell trades on interconnectors with implicitly allocated capacity

In the Enhanced National Stretch case we have calculated periods and volumes of potential IC sell trades on the Norwegian interconnector to help to solve transmission constraints (instead of accepting bids in the BM) using the following approach. We have only considered:

— Hours when the BM volume weighted average accepted bid price is lower than the NO2 intraday price minus a €10/MWh discount (compared to -€15/MWh in the Enhanced National case)

— Days when transmission constraints costs are higher than £2m

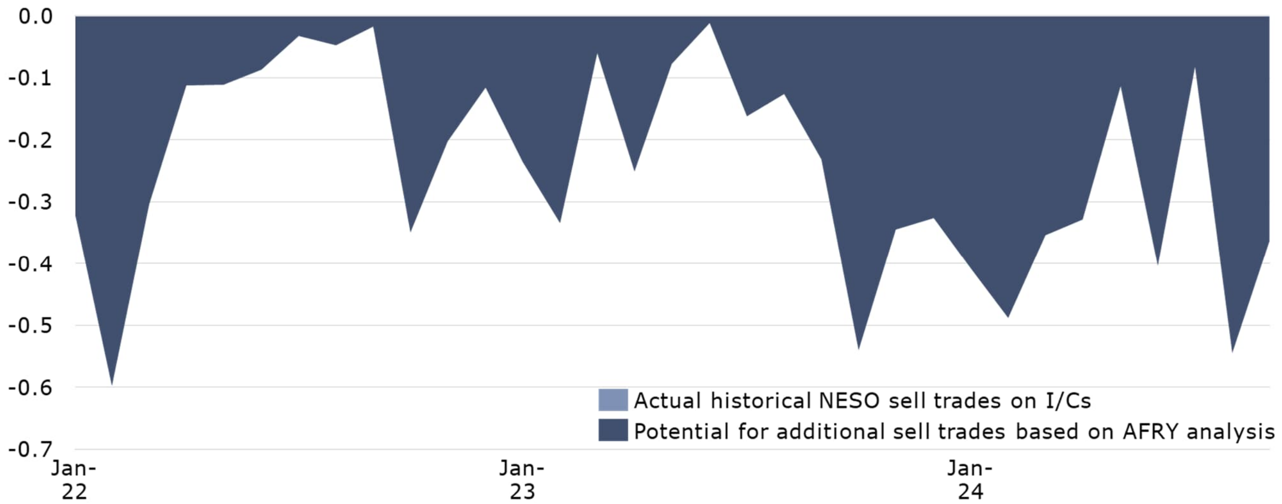
— Hours when GB is a net importer or exported less than 500 MWh on the NSL interconnector

— The maximum potential volume in each hour is capped by the lowest of:

- the remaining import capacity on the NSL interconnector
- 80% of the accepted bid volume in that hour (to reflect the fact that some BM actions are for localised needs and cannot be replaced by I/C sell trades)
- 1120 MW (to reflect the fact that it appears to be rare for NESO to fully reverse flows on I/Cs via trades)

The resulting additional potential buy trade volume compared with the actual volume is shown in Exhibit B.16.

Exhibit B.16 – Potential monthly sell trade volume identified on NSL (TWh/month)

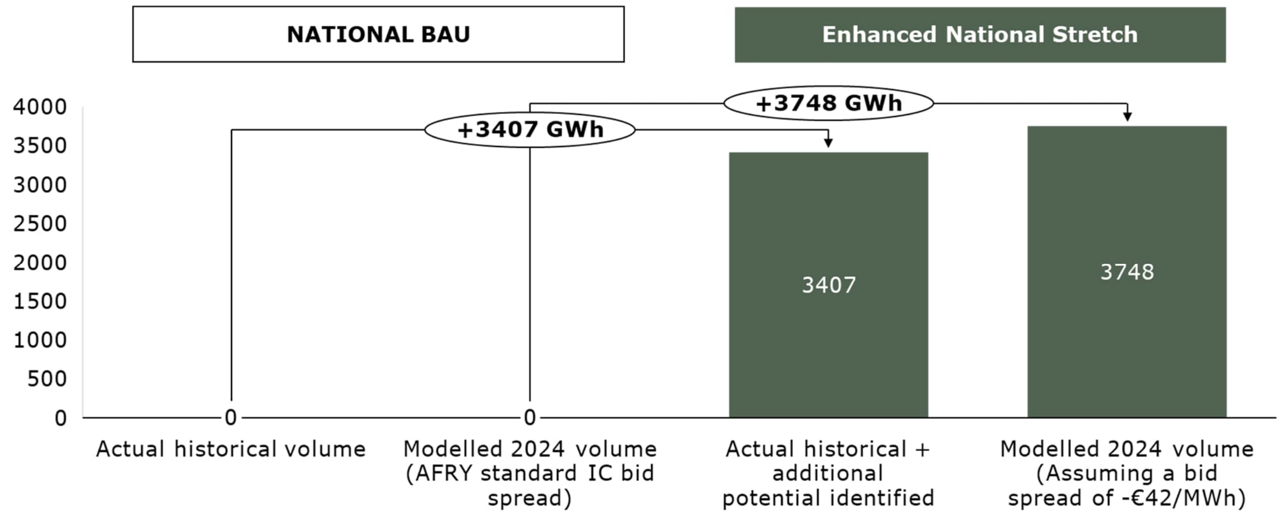


Sources: AFRY

Based on our estimate of the volumes of potential sell trades on NSL, we calibrated our BID3 redispatch model using the 2024 modelled year, on the currently theoretical assumption that NESO countertrading actions are possible under Enhanced National Stretch arrangements.

As illustrated in Exhibit B.17, to achieve the identified NSL sell trade potential, we found that the required bid spread for an Enhanced National Stretch case would be -€42/MWh (real 2023).

Exhibit B.17 – Potential and modelled IC sell trade volumes on the NSL interconnector (GWh/annum)



B.1.4 Summary of modelling assumptions related to expanded potential for interconnector countertrading

Exhibit B.18 summarises the modelling assumptions related to improved interconnector countertrading in the Enhanced National and Enhanced National Stretch cases, with the assumptions for the National BAU case also shown for comparison.

Exhibit B.18 – Summary of modelling assumptions for expanded interconnector countertrading (€/MWh, real 2023)

Element	BaU	Enhanced National	Enhanced National Stretch
1 9 Expanded NESO counter-trading on I/Cs	**All ICs (excl. Ireland & Norway)**	**All ICs (excl. to Ireland & Norway)**	**All ICs (excl. to Ireland & Norway)**
	- Standard AFRY assumptions for interconnector bids and offers	- Offer: standard AFRY assumption **minus €24/MWh** - Bid: standard AFRY assumption minus a discount of **€18/MWh**	- Offer: standard AFRY assumption **minus €42/MWh** - Bid: standard AFRY assumption minus a discount of **€26/MWh**
	ICs to Ireland & Norway	**ICs to Ireland & Norway**	**ICs to Ireland & Norway**
	- No countertrading	- Offer spread: High values assumed - Bid spread: **-€63/MWh**	- Offer spread: Enhanced National assumption **minus €24/MWh** - Bid spread: **-€42/MWh**

B.2 Management of interconnectors post-gate closure – expanded NESO use of interconnectors in balancing timeframes

B.2.1 Current arrangements

Currently, post-gate closure redispatch of interconnectors is possible via a SO-to-SO trades for balancing energy on most GB interconnectors (the exceptions are NEMO to Belgium and NSL to Norway). The non-dynamic pricing (which is generally unattractive to NESO) and lack of firmness tends to result use of SO-SO trades as a last resort for system security issues, although a 25MW tranche is used more regularly on the Irish interconnectors for mutual benefit. Prior to Brexit, GB was part of the cross-border balancing initiative with continental SOs, and here is provision within the TCA to develop a bespoke GB-EU balancing platform in place of participation in TERRE or MARI.

B.2.2 Enhanced National – assumptions for expanded NESO use of interconnectors in balancing timeframes

Building block		Enhanced National
Management of interconnectors	**Post-gate closure: Expanded NESO use of interconnectors in balancing timeframes**	2 Improved NESO access to interconnector assets post gate closure through expansion of SO-SO trading

In the National BAU case we reflect a 25MW tranche of capacity on the interconnectors with Ireland with low bid/offer spreads to reflect the current level of readily available capacity in balancing timeframes. We do not assume a flexible capacity tranche on any other interconnectors in the National BAU case.

In the Enhanced National case we assume that a similar level of balancing flexibility through improved SO-SO trading arrangements is achieved through mutually beneficial agreements, and reflect this in a 25MW tranche of capacity with low bid offer spreads, as for the Irish interconnectors in the BAU. Expanding SO-to-SO trading to at least a similar level to that with the Irish SO should be achievable, given the small size of Ireland relative to other interconnected markets.

B.2.3 Enhanced National Stretch – assumptions for expanded NESO use of interconnectors in balancing timeframes

Building block		Enhanced National Stretch
Management of interconnectors	Post-gate closure: Expanded NESO use of interconnectors in balancing timeframes	10 Improved NESO access to interconnector assets post gate closure through improved cross-border balancing via a bilateral cross-border balancing platform (or via direct nomination between SOs)

In the Enhanced National Stretch case we assume a greater level of interconnector flexibility in balancing timeframes could be achieved through either a cross-border balancing platform or ability for interconnected TSOs to directly nominate interconnector flows.

It is difficult to judge how much additional flexibility such arrangements could create relative to improved SO-SO; we conservatively assume it could double the relatively small levels of flexibility assumed in the Enhanced National case, reflected in a 50MW tranche of flexible capacity being available in balancing timeframes.

B.2.4 Summary of assumptions for expanded NESO use of interconnectors in balancing timeframes

Exhibit B.19 – Summary of modelling assumptions for expanded use of interconnectors in balancing timeframes

Element	BaU	Enhanced National	Enhanced National Stretch
Expanded use of interconnectors in balancing timeframes	**All ICs (excl. Ireland)**	**All ICs (excl. to Ireland & Norway)**	**All ICs (excl. to Ireland & Norway)**
	- Negligible use in balancing timeframes assumed	- 25MW capacity tranche with a low bid-offer spread	- 50MW capacity tranche with a low bid-offer spread
	ICs to Ireland	**ICs to Ireland or Norway**	**ICs to Ireland or Norway**
	- 25MW capacity tranche with a low bid-offer spread	- 25MW capacity tranche with a low bid-offer spread	- 50MW capacity tranche with a low bid-offer spread

B.3 Management of small-scale assets - Improved NESO optimisation of small-scale BMU assets

Building block		Enhanced National	Enhanced National Stretch
Management of small-scale assets	**Improved NESO optimisation of small-scale BMU assets**	Improved NESO forecasting tools and optimisation processes to improve NESO access to small-scale BMU assets in balancing and redispatch	

Increases in the ability to see and co-ordinate many small offers from small-scale assets would improve NESO's ability to rely on disaggregated resources to meet balancing needs at lower cost.

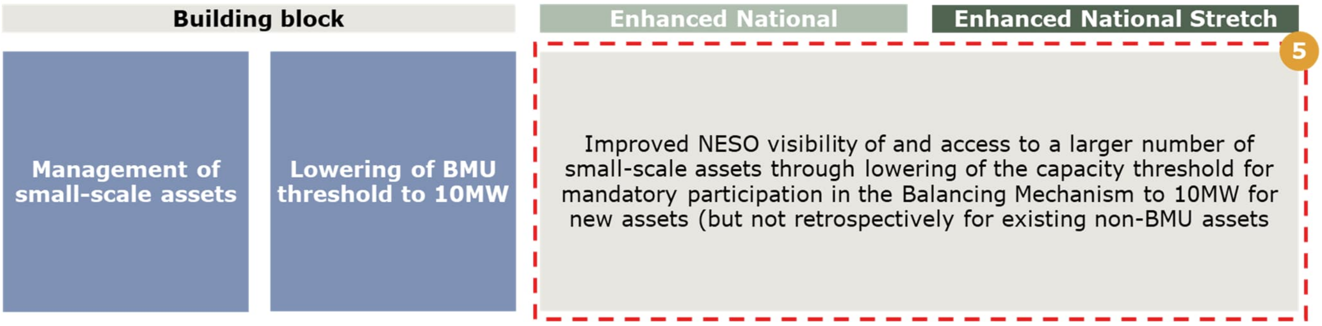
B.3.1 Summary of modelling assumptions related to improved optimisation of small-scale assets

Improved NESO optimisation of small-scale assets in the BM should enable greater flexibility in NESO's use of these assets, and their utilisation relative to other assets. To reflect this, in the Enhanced National and Enhanced National Stretch cases we have reduced bid and offer multipliers (i.e. the percentage mark-up on the true variable costs of a bid or offer) from small-scale plants by 10 percentage points, relative to the assumptions in the National BAU case.

Exhibit B.20 – Summary of modelling assumptions for improved optimisation of small-scale assets

Element	BaU	Enhanced National	Enhanced National Stretch
Improved NESO arrangements for optimisation of small-scale assets	Standard AFRY assumptions small-scale asset bids and offers in the Balancing Mechanism	Standard AFRY assumptions for small-scale assets with bid and offer multipliers **reduced by 10 percentage points**	

B.4 Management of small-scale assets – lowering of the BMU threshold to 10MW



B.4.1 Current arrangements

Under current arrangements, a rising share of distribution connected capacity on the system has no requirement to participate in the Balancing Mechanism (BM) because it is below the minimum size above which the requirement to participate becomes mandatory. Currently these mandatory minimum size thresholds vary by transmission network area as follows:

- North Scotland Scottish Hydro Electric Transmission (SHETL): >= 10MW
- South Scotland Scottish Power Transmission (SPT): >= 30MW
- England and Wales National Grid Electricity Transmission (NGET): >= 100MW

Making more of these embedded resources accessible to NESO in the BM through a lowering of the minimum capacity threshold for mandatory participation would provide an additional pool of balancing resources directly accessible in the BM, at a potentially lower cost.

B.4.2 Summary of modelling assumptions related to improved – lowering of the BMU threshold to 10MW

Lowering the mandatory BM participation threshold for existing assets would be a retrospective change and likely to be subject to legal challenge. For this reason, we assume a lowering of the minimum capacity threshold to 10MW across all of GB only for new assets (per GC0117[56]) from 2027 onwards.

In both the Enhanced National and Enhanced National Stretch cases, we assume that, from 2027 onwards, all new capacity above 10MW will participate in the Balancing Mechanism, while the current thresholds are assumed to remain in place in the National BAU case.

In order to determine the future share of capacity that will be affected by the change in minimum size for mandatory participation, we have considered the current share of small-scale assets at different sizes in different locations. The following sources were considered for this assessment:

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[56] GC0117: Improving transparency and consistency of access arrangements across GB by the creation of a pan-GB commonality of power station requirements

- Capacity market register
- NESO CBA on Grid Code Modification GC0117 (published in 2023)
- Digest of UK Energy Statistics (DUKES)
- AFRY's own market information (mainly on storage and small biomass)

From these sources, we have obtained the share of current and planned capacity above 10MW for each technology in England. We assume that, for each technology, the current distribution of capacity by size remains the same in the future. In the Enhanced National and Enhanced National Strech cases, the assumption that new assets above 10MW will participate in the BM is implemented from 2027 by technology, as an increased share of future capacity, as detailed in Exhibit B.21 below.

Exhibit B.21 –Assumed share of new assets in England that will participate in the BM from 2027 onwards as a result of lowering the BMU threshold to 10MW

Element	Technology	BaU	Enhanced National	Enhanced National Stretch
5 Lower BMU threshold for new assets	Batteries	65%	95%	
	CHP	90%	95%	
	Engines	15%	80%	
	GT	75%	100%	
	Small biomass	5%	80%	
	Solar PV	<1%	25%	

Note: The shares of battery capacity in the BM presented here relate to grid connected batteries only; they do not include very small-scale residential batteries, which in our modelling are included within flexible demand.

B.5 Management of storage assets – improved market arrangements for optimisation of storage assets

Building block		Enhanced National	Enhanced National Stretch
Management of storage assets	Improved NESO market arrangements for optimisation of storage assets	8 Improved management of intertemporal issues through the capability for NESO to 'commit' usable energy from storage assets ahead of gate closure	

B.5.1 Current arrangements

For various reasons, storage assets are sometimes not utilised by NESO in planning and operational timeframes despite appearing to be a lower cost option, which is the problem known as 'skipping'. The definition of skip rates and the methodology used to calculate them (e.g. which system action or other actions are removed from the merit order used for assessment) can lead to varying results for skip rates. In July 2023 the Energy Storage Network published an open letter citing an average skip-rate for a representative battery in the BM of 80%[57], while in September 2024 a letter from 4 storage companies suggested a skip-rate of more than 90% for some sites in constrained areas[58]. In the same month NESO referred (in an interview with Financial Times) to skip rates batteries having been reduced to 30%, as a result of software changes introduced in December 2023. More recent analysis commissioned by NESO and published in December 2024 suggests battery skip rates between January and July 2024 were close to 80%[59,60].

Beyond the skip rate discussion, there is a currently a fundamental limitation in that NESO cannot be certain about the available 'usable' energy for future settlement periods when making scheduling decisions.

B.5.2 Summary of modelling assumptions related to improved market arrangements for storage assets

In the National BAU case, we derate battery capacity in the Balancing Mechanism by 50% (by derate, we mean reduce the potentially available capacity by this factor), to reflect the fact that NESO cannot currently be certain about the available 'usable' energy for future settlement periods when making scheduling decisions, and to reflect the fact that batteries are,

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57 https://www.neso.energy/document/285011/download
58 https://www.zenobe.com/insights-and-guides/industry-calls-for-urgent-government-action-on-battery-storage-to-deliver-2030-target-and-cut-household-bills/#:~:text=Our%20own%20data%20%E2%80%93%20verified%20by,generation%20is%20being%20used%20instead.
59 https://www.neso.energy/defining-measuring-and-addressing-skip-rates

at times, 'skipped'. This is an approximation which doesn't fully reflect the potential for the full capacity of the battery to potentially respond but only 20% of the time, which may be closer to the current reality[61].

With the ongoing work by NESO to address storage skip rates and assuming the development of a product which could enable NESO to commit useable energy from storage assets, many of the existing inefficiencies could be overcome. To reflect this, we reduce derating factors for battery capacity in the Balancing Mechanism to 10% in both the Enhanced National and Enhanced National Stretch cases (i.e. 90% of the potential capacity is available in the Balancing Mechanism). Assumptions across all cases are summarised in Exhibit B.22.

Exhibit B.22 – Summary of capacity derating factors in the Balancing Mechanism for battery storage

Element	BaU	Enhanced National	Enhanced National Stretch
8 Improved NESO market arrangements for optimisation of storage assets	50%	10%	10%

[61] The analysis on skip rates published by NESO in December 2024 was published after the modelling assumptions for this study were finalised; had it been published sooner we would have assumed a higher capacity derating factor for storage in the Balancing Mechanism in the National BAU case than the 50% we actually assumed, which would be likely to result in at least some reduction in overall welfare in the National BAU case (and so result in the other cases showing a larger gain in welfare).

Annex C Modelling methodology

C.1 Modelling approach

In our modelling, we represent a day-ahead market and a Balancing Mechanism for both the national and zonal cases. The modelled Balancing Mechanism also reflects the potential for NESO to take advance actions ahead of gate closure (e.g. interconnector countertrades) which are strictly outside the actual Balancing Mechanism. For all cases, we have modelled transmission constraints and inertia constraints, but not other system constraints (e.g. reserve), forecast error or imbalance costs. In the modelled national cases, the transmission and inertia constraints only appear in the Balancing Mechanism, while in the Zonal cases, transmission constraints are resolved as part of the day-ahead market optimisation, leaving only inertia constraints for resolution in a Balancing Mechanism.

C.1.1 Operational efficiency

The modelling of the market design cases was based on the operational efficiency focus of the analysis.

For the national cases to perfectly replicate the pattern of dispatch achieved in the modelled zonal market, the Balancing Mechanism in the modelled national cases has to achieve the same pattern of dispatch against transmission constraints as the modelled zonal market day-ahead. This would be theoretically possible if all resources (including interconnectors) are available in the Balancing Mechanism with the same merit order of costs, and NESO algorithms can achieve the same degree of optimisation as the zonal day-ahead market. Even then (i.e. with same final dispatch), in the national market generators making a positive gross margin at the day-ahead stage keep this when subsequently constrained-off in the Balancing Mechanism. When this happens to a domestic generator, there is a welfare transfer from consumers to generators, but total welfare for Great Britain is unchanged. However, when this happens to an overseas generator (modelled as interconnector redispatch), the transfer is from GB consumers to non-GB generators, which is a reduction in total GB welfare.

In our modelling of the National BAU case, current limitations on scheduling and dispatch are reflected either in some assets not being available at all in the Balancing Mechanism, or available but with less flexibility, as reflected in higher bid/offer spread assumptions.

As detailed in Annex B, In the Enhanced National case and Enhanced National Stretch cases, improved arrangements for interconnection, storage and small-scale assets improve the availability and/or flexibility of these asset classes in the modelled Balancing Mechanism, reflected in a larger share of capacity being present in the BM, and/or with lower bid/offer spreads. In the case of interconnection, this includes improved interconnector flexibility from credibly achievable expansions of NESO countertrading ahead of gate closure, as well as improvements in flexibility post-gate closure.

We have not assumed any improvements to resource availability or flexibility within the modelled Balancing Mechanism for the zonal cases; removal of the requirement for the Balancing Mechanism to entirely solve transmission constraints reduces the benefits that BM reform could achieve in a zonal market, although a share of them may still be cost-effective to implement. We have modelled intra-GB congestion rent in the zonal cases; however locational losses have been modelled as flat constant values by zone in all cases (rather than dynamically).

C.1.2 Investment

Locational investment patterns for generation capacity and transmission network expansion were determined based on the National BAU case, and then held fixed in all the other cases

In the National BAU case, investment patterns reflect

- BAU CfD arrangements, comprising award of a 15-year contract based on lowest price, and payment based on metered output except in any hour when the reference price is below zero. Supported plants are assumed to bid into the energy market at very low prices[62].
- locational transmission charges[63], based on NESO's latest 5-year forecast of TNUoS charges[64], held flat from 2030 onwards. The resulting assumptions on locational transmission charges for renewable technologies are shown in Exhibit C.1.

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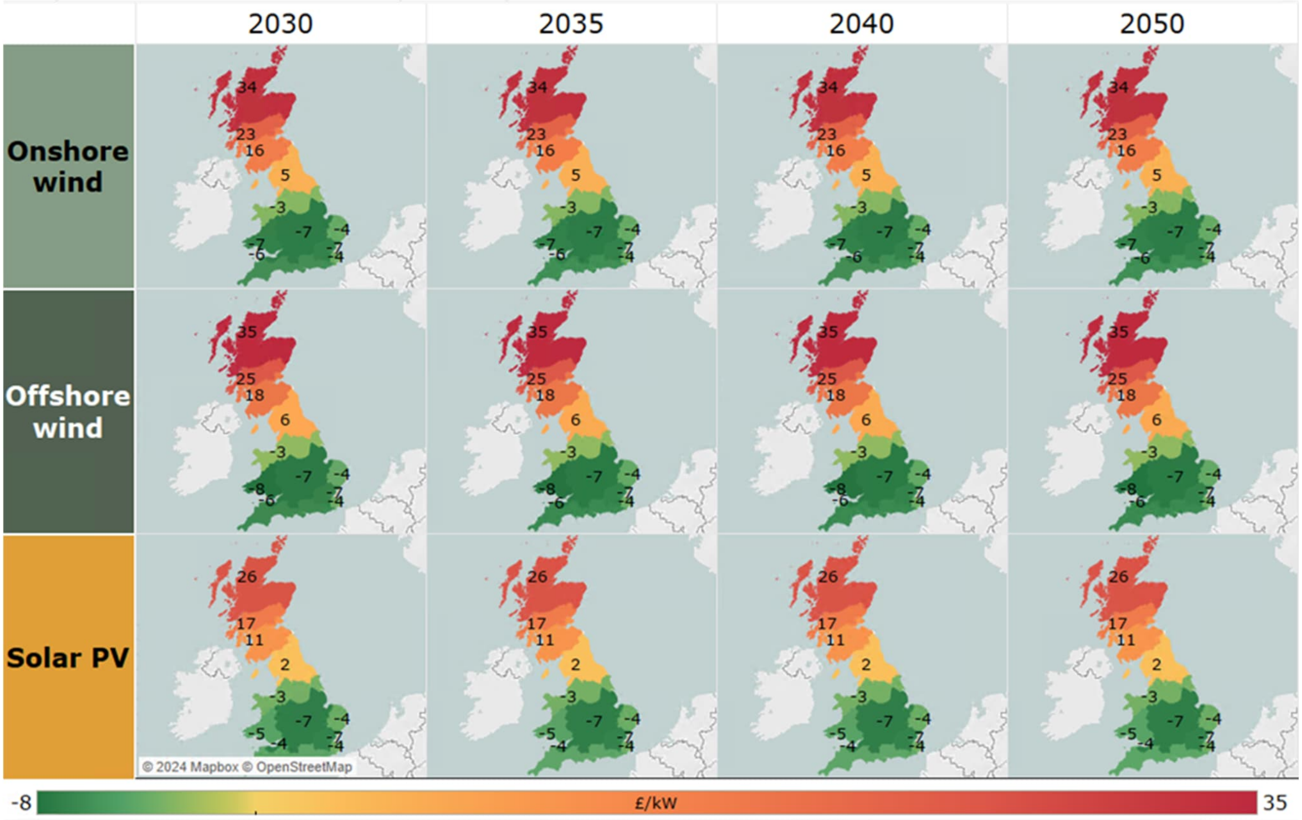
[62] Onshore wind: £0.03/MWh; offshore wind: £0.02/MWh; solar PV: £0.01/MWh.
[63] This refers to the wider tariff element only – i.e. we are not assuming a change on local circuit changes or offshore local generation tariffs, which would proceed as in the status quo.
[64] Five-Year View of TNUoS Tariffs for 2025/26 to 2029/30 (NESO, April 2024) https://www.neso.energy/document/317561/download

Exhibit C.1 – Locational grid charges for renewable technologies in the national cases (£/kW, real 2023)



C.1.3 Cost of capital assumptions

C.1.3.1 National Enhanced, National Enhanced Stretch and Zonal cases

We have assumed that relative to the National BAU case, there is no change in hurdle rate for any technology in the National Enhanced or Enhanced National Stretch cases.

To reflect the increased risk of revenue volatility within a zonal market (across both a likely increase in volatility in energy market revenues, and a decrease in grid charge volatility from the likely removal of locational grid charges), the Zonal case assumes the following changes in hurdle rates relative to the National BAU case:

- CfD-supported capacity: 0% (+0 bps)
- Non-CfD supported capacity (excluding OCGT or storage): 1% (+100 bps)
- OCGT capacity: 0.5% (+50 bps)
- Storage capacity: 0% (+ 0 bps)

CfD-supported plants are assumed indexed to the zonal price, and no increase in hurdle rate relative to National BAU is assumed[65]. As we have assumed 15-year CfD support contracts followed by a merchant tail for the remainder of the economic lifetime, this does not reflect any increase in hurdle rate as a result exposure to zonal prices after the CfD-contract has ended, and so is a conservative assumption. In reality, a windfarm with a 30-year economic lifetime and a 15-year support contract would face locational price exposure which investors would pro-rate, with the effect that the CfD contract would reduce but not eliminate any increases to cost of capital, although the likely removal of locational variations in TNUoS would offset this.

For the non-CfD supported capacity, the smaller increase for OCGT capacity reflects its lower exposure to the energy market as a share of its total revenue (including from the Capacity Market), while for storage, the potential for increased within-day energy market volatility to benefit storage may offset the increased uncertainties associated with predicting its location and durability over time.

C.1.3.2 Zonal – Cost of Capital sensitivity

We have also run a cost of capital sensitivity on the Zonal case (the Zonal – Cost of Capital sensitivity). In addition to the increases in hurdle rates assumed in the Zonal case (see above), this sensitivity assumes the following additional increases in hurdle rates relative to the National BAU:

— CfD-supported capacity: 1% (+100 bps)

C.1.3.3 Existing plants

Note that in the Zonal and Zonal – Cost of Capital sensitivity cases, we have not considered the effect of a higher risk in a zonal market for existing plants in this analysis. While this does not, by definition (since they are existing) affect plant build (and existing renewable plants are still likely to make enough money to recover their annual fixed costs and so would not decommission early), there would be impacts on existing plants, including potentially higher costs for refinancing, and a lower price if trying to sell the asset.

C.1.4 Modelled market design cases

We have modelled four main market design cases based on national business-as-usual arrangements (National BAU), enhanced national arrangements (Enhanced National), more ambitious enhanced national arrangements (Enhanced National Stretch), and a zonal market (Zonal).

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[65] As we have not changed the generation mix in the zonal case compared to BAU, this is not a fully internally consistent, but is a reasonable approximation for the purposes of plant dispatch.

Our market design cases model different combinations of the following elements, which are combined in each case to form an internally consistent market design:

— wholesale market granularity: national or zonal (11 zones)

— market redispatch to respect transmission and inertia constraints (in the national cases), or inertia constraints alone (in the zonal cases)

The modelled cases are summarised in Exhibit C.2.

Exhibit C.2 – Summary of modelled market design cases

	NATIONAL BAU	ENHANCED NATIONAL	ENHANCED NATIONAL STRETCH	ZONAL*
INVESTMENT PATTERNS	• Generation and network build and locations reflect: • Grid charges based on current TNUoS methodology • BAU CfD arrangements	• Same pattern of generation capacity and transmission build and location as National BAU	• Same pattern of generation capacity and transmission build and location as National BAU	• Same pattern of generation capacity and transmission build and location as National BAU
WHOLESALE MARKETS	• National	• National	• National	• Zonal (based on 11 price zones)
REDISPATCH	• Balancing Mechanism resolves transmission and inertia constraints • No change to current arrangements for SO management of interconnectors, small-scale assets or storage	• Balancing Mechanism resolves transmission and inertia constraints • Arrangements for SO management of interconnectors, small-scale assets and storage reflect Enhanced National market design	• Balancing Mechanism resolves transmission and inertia constraints • Arrangements for SO management of interconnectors, small-scale assets or storage reflect Enhanced National Stretch market design	• Balancing Mechanism resolves inertia constraints • No change to current arrangements for SO management of interconnectors, small-scale assets or storage

* The Zonal – Cost of Capital sensitivity case is identical to the Zonal case, with the sole exception of the +100 bps in hurdle rates for CfD-supported capacity.

Note: Redispatch is also possible in all cases (including Zonal) due to CfD plants having different bidding incentives in the Balancing Mechanism (and, in reality, also intraday) compared to day-ahead.

C.1.5 Socio-economic welfare assessment

As our primary quantitative metric for each case, we have evaluated the aggregate economic welfare to Great Britain actors (which should be the primary focus of policy makers). The distribution of these benefits is also important, but as welfare is likely to be reallocated between producers and consumers through other policy instruments (including through grandfathering of existing rights and different degrees of shielding from the effects of changes), we have not examined these in detail. Distribution should be of secondary importance, given a larger total economic welfare can be reallocated between producers and consumers once obtained, but not otherwise. Note that our modelling is based on equilibrium and perfect foresight, which smooths the results of any market regime.

Net Present Values (NPV) of economic welfare provided in this report are calculated over an appraisal period from 2030 to 2050 inclusive, assuming a 3.5% discount rate. Modelled years were 2030, 2035, 2040 and 2050, with values for the non-modelled years in between based on interpolation between modelled years. Each future year is given a discounted value, starting with 2030 indexed to a value of 1. This includes all years, both modelled years and years in between. Final system costs included direct capex values from the modelled years[66]. Variable and annual fixed costs from each modelled year are counted for each of the years the modelled year represents. On this basis, the NPV values are therefore 2030 values for a 21-year period. We then further discount these values in order to bring them to a 2025 indexed value. Effectively this represents the NPV of the market arrangements from 2030, at the point a decision to retain or change them is made (assumed to be in 2025)[67].

C.2 Modelled scenario

To compare the benefits and disbenefits of the different market design cases, we have modelled a scenario which achieves a net zero power grid by 2035.

This is based on the Holistic Transition Pathway from NESO's Future Energy Scenarios (FES) 2024. The Holistic Transition Pathway was selected as representing a balance in decarbonisation effort between electrification and hydrogen supply, as well as achieving a net power grid by 2035 (in 2033).

- For offshore wind, the scenario was amended to reflect a more realistic rate of capacity deployment. In the published Holistic Transition Pathway, 54GW of offshore wind is commissioned by 2030. We have amended this assumption to reflect 50GW by 2033, which (while still quite stretching) we consider to be more credible, and aligning with the year net zero is achieved in the scenario.
- We modelled the scenario to 2050, with modelled years 2030, 2035, 2040 and 2050. As the first modelled year is 2030, the modelled effects of improved market design (whether National Enhanced, Enhanced National Stretch or a zonal alternative) can only be compared from 2030 onwards; while a zonal market may be possible to implement from 2030, the additional benefits that could arise from implementing some or all of the features in the enhanced national market designs (either ahead of or in place of a zonal market) have not been quantified.

C.2.1 Demand

The Holistic Transition Pathway is characterised by high levels of consumer participation, electrification of heat and transport and correspondingly high levels of power demand, with more modest growth in hydrogen demand. End use power demand excluding electrolysis has a compound annual growth rate of 2.6% between 2025 and 2050, reaching 363 TWh in 2035 and 503 TWh in 2050. Within this, electric vehicle (EV) demand rises from 5TWh in 2023 to 64TWh in 2035 and 122TWh by 2050 (respectively 17% and 24% of total end user demand).

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[66] The capex is included in the NPV using the Spackman approach.
[67] We assume for the purposes of the NPV calculation that changes to market design implemented from 2030, both for Zonal and Enhanced National market designs; in practice significant elements of an Enhanced National design are likely to be implementable before 2030, although they could also be implemented ahead of the introduction of a zonal market.

An important assumption is the share of EV demand that is assumed to be price responsive and so flexible. Price-responsive demand responds implicitly to wholesale prices in both national and zonal markets, and there is an ongoing programme of work by NESO to enable flexible demand to participate in the Balancing Mechanism. However, we believe that explicit participation (through e.g. the Balancing Mechanism) is harder for demand-side resources due to the need to conform to a specific product definition and offer a service for sale which (e.g. NESO) must then buy (not skip), so some residual inflexibility compared to a zonal market is likely to remain.

Therefore, our modelling of the Balancing Mechanism is based on completely inflexible demand. This prevents flexible demand from being fully optimised in the national case.

To prevent this unduly biasing comparisons between the national cases and the zonal cases, we have adopted conservative assumptions about the level of demand flexibility – from 2030 onwards, we assume 10% of EV charging demand is highly price responsive, and we do not assume any price responsive vehicle-to-grid capability.

Hydrogen demand is confined to isolated clusters, and all hydrogen production is constrained to come from electrolysis.

In the National market cases, we assume that electrolysis does not face locational TNUoS charges whereas in the zonal cases, electrolysis is exposed to the locational energy prices.

In terms of the location of power demand, we have assumed that the regional distribution of power demand in future years remains as projected in the Energy Ten Year Statement 2023 (ETYS 23), with zonal demand scaling with total demand.

C.2.2 Generation capacity

In the National BAU case, modelled generation capacity expansion is based on a combination of:

- Pre-defined exogeneous input assumptions from the FES 2024, with locations based on the Energy Ten Year Statement (ETYS) 2023.
- Achievement of the offshore wind 50GW target by 2033 as an exogeneous input (for capacity entering after AR6 we assume a degree of locational optimisation between different lease areas is possible and this capacity is distributed between lease areas based on assessment of the costs in these locations).
- Additional economic capacity built endogenously within the model, subject to:
  - all large-scale renewable capacity is assumed to be CfD-supported under the National BAU CfD arrangements
  - a long-term budget allocation of zero for total CfD payments (in other words, over the course of their lifetimes, supported plants eventually pay back as much as they receive)

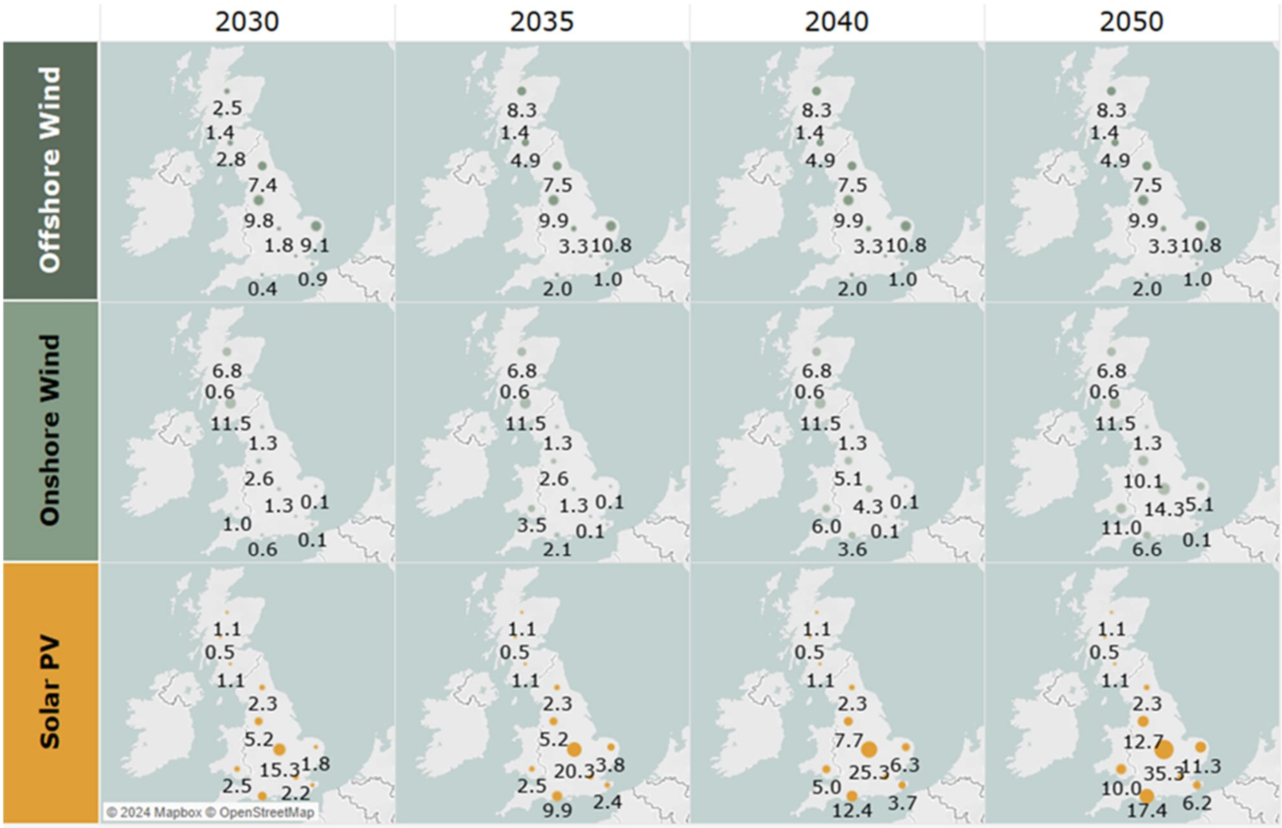
— a minimum level of renewable generation procurement each year from onshore wind and/or solar PV (3TWh in CT, 2TWh in ST) reflective of the likely reality of annual CfD auctions going forward

— caps on the rate of renewable capacity build by location

— In the Enhanced National, Enhanced National Stretch and Zonal cases, the total generation capacities by technology and their locations are fixed based on the pattern of build obtained in the National BAU case.

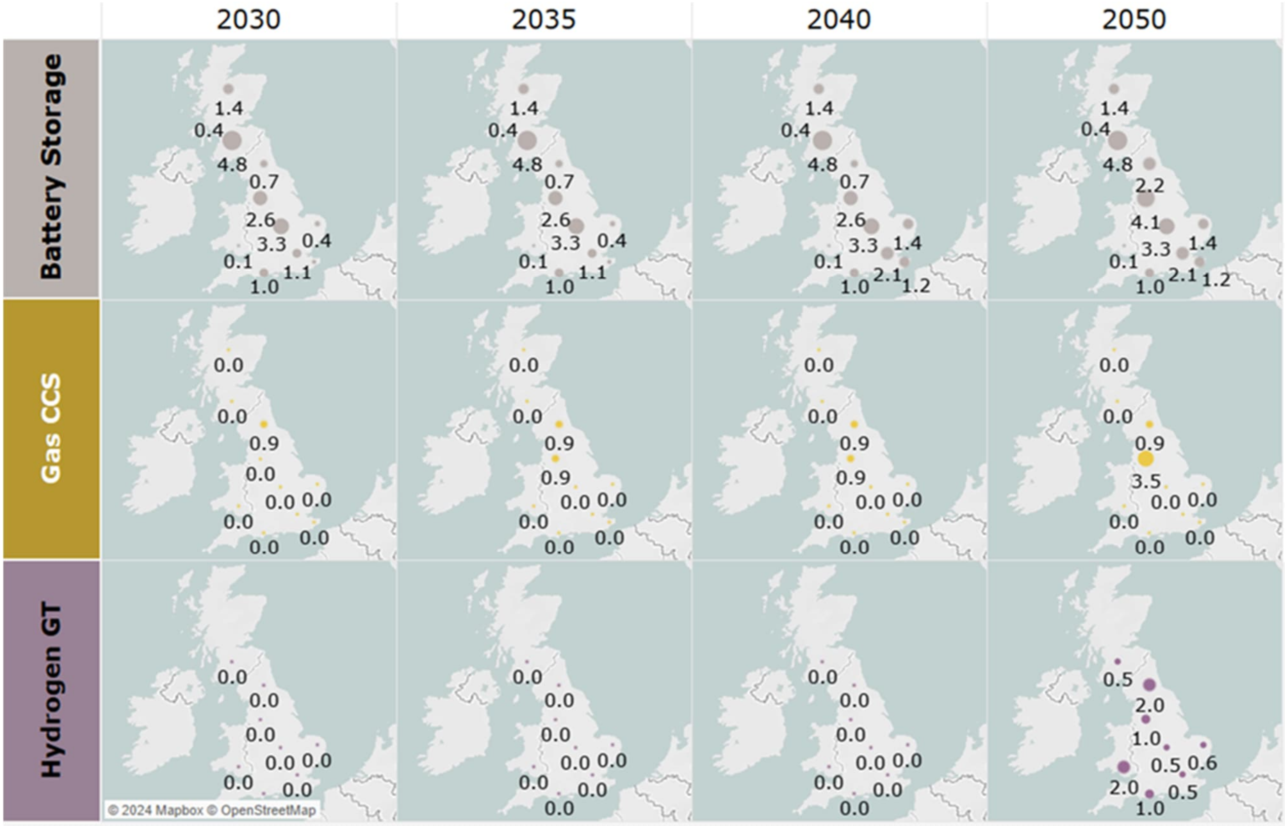
— The total new build capacity by location for the main renewable technologies common to all the market design cases is shown in Exhibit C.3, and the equivalent for storage and low carbon thermal technologies is shown in Exhibit C.4.

Exhibit C.3 – Cumulative new build renewable capacity by location – all cases (GW)



Note: In the case of offshore wind, the capacities by location reflect the zone of the onshore connection point.

Exhibit C.4 – Cumulative new build battery and thermal capacity by location – all cases (GW)

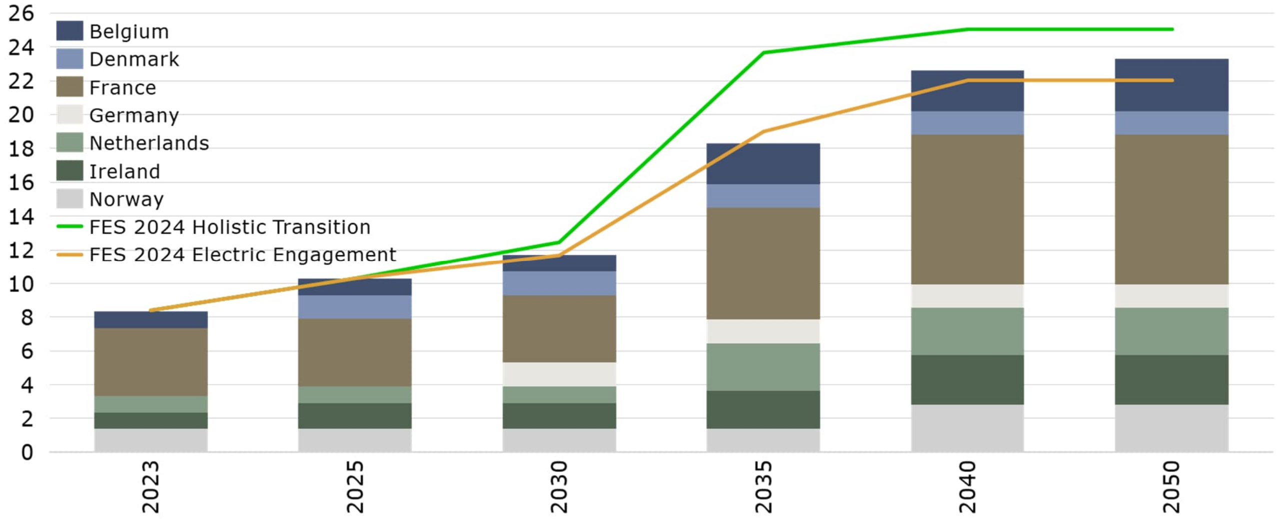


C.2.3 Interconnection

In the National BAU case, interconnector capacity reflects exogenous assumptions to 2035, and, post-2035, additional merchant economic capacity built endogenously within the model.

In the modelled scenario, total interconnector capacity including additional economic build post-2035 reaches 18GW in 2035 and 23GW in 2050, and is summarised in Exhibit C.5. The total outturn capacity adheres more closely to the published total for the Electric Engagement Pathway, than the Holistic Transition Pathway, reflecting a more conservative approach to interconnector build.

Exhibit C.5 – Installed interconnector capacity (all cases) (GW)



For the interconnected markets, we modelled with fixed capacity assumptions, based on previous analysis carried out by AFRY, optimising dispatch and interconnector flows.

In the Enhanced National, Enhanced National Stretch and Zonal cases, the total interconnector capacity assumptions are fixed based on the pattern of build obtained in the National BAU case.

C.2.4 Network build

In the National BAU case, our network expansion methodology is based on exogeneous assumptions from the ETYS 2023 and Beyond 2030 plan until 2030.

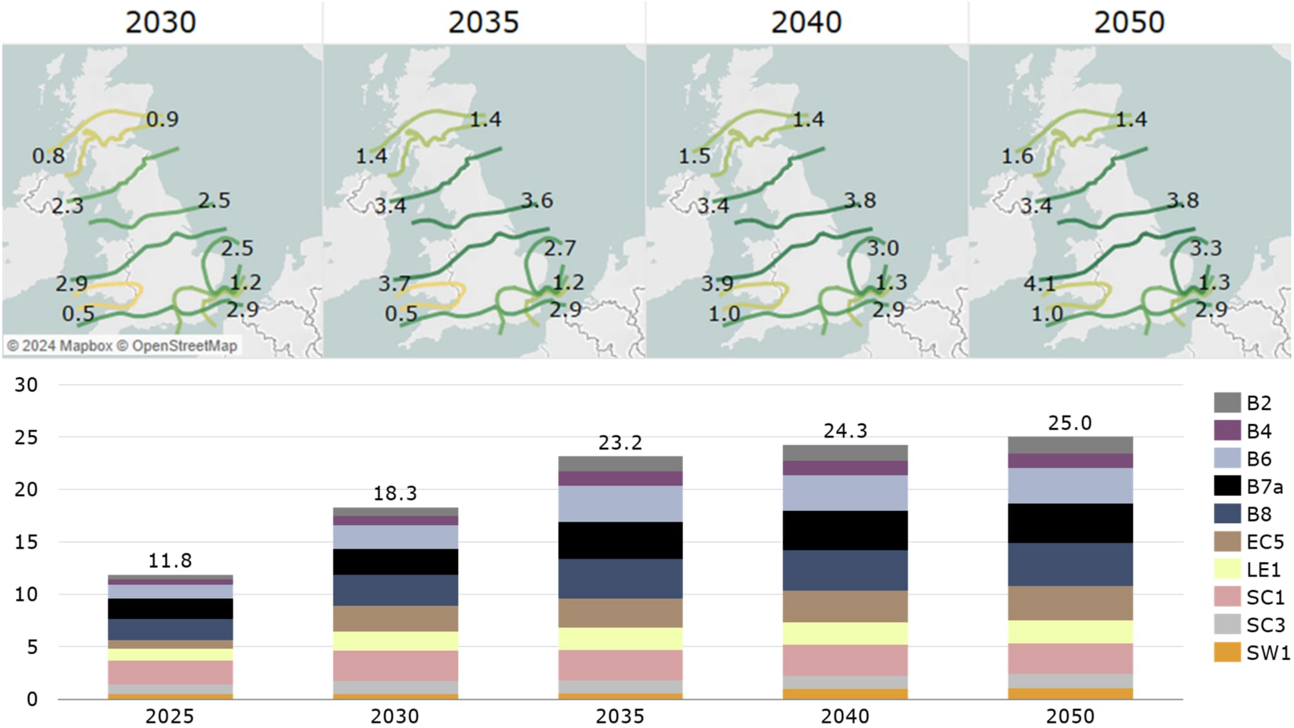
From 2035 onwards there is additional endogenous network expansion, including economic assessment of longer-term options in the Beyond 2030 plan. This takes into account locational patterns of generation and demand, which in turn is determined by the impact of the locational signals on generation and on electrolysis. In the first instance this is based on a least cost approach using the BID3 Auto Build module, and then subsequently refined to reflect:

— the cost of an additional 1MW of line capacity compared with the congestion cost (or, in the national cases, redispatch costs) that it would relieve

— the lumpy nature of network build in practice (particularly for HVDC lines)

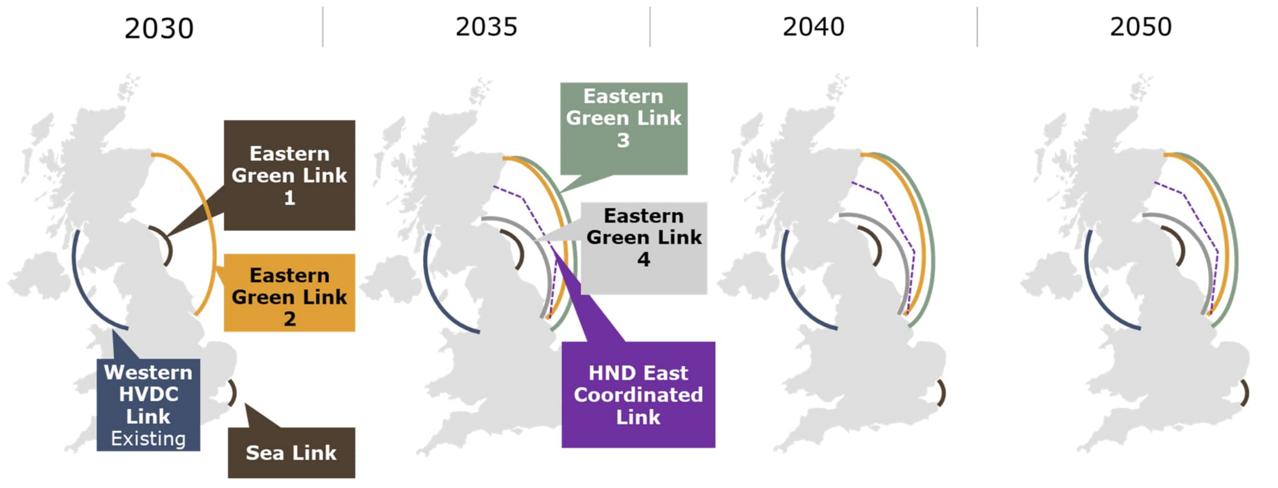
Total AC transmission capacity by boundary is shown in Exhibit C.6, while expansion of the HVDC network is shown in Exhibit C.7; all of the HVDC lines indicated in the Beyond 2030 plan (Sealink, Scotland to England Green Links 1 to 4, and the HND East Coordinated Link) are built in the scenario by 2035.

Exhibit C.6 – AC transmission capability by boundary (cumulative '000 GWkm)



Note: Increases in AC transmission capability to 2035 reflect both build of new lines and non-build solutions to increase capability.

Exhibit C.7 – HVDC network expansion



In the Enhanced National, Enhanced National Stretch and Zonal cases, the network build assumptions are fixed based on the pattern of build obtained in the National BAU case.

C.2.5 Inertia requirements

In addition to transmission constraints, we model a national inertia constraint, which is resolved in a Balancing Mechanism in both the national and zonal cases.

We assume that the minimum inertia requirement reduces from 120GVAs to 102GVAs by 2030, and remains at 102GVAs until 2050, and that the new sources of inertia procured recently (mainly via the Stability Pathfinders) come online by 2030, resulting in ~32GVAs of new inertia provision by 2030.

From 2035 onwards, further deployment of economic sources of inertia in the form of synchronous condensers is modelled; further synchronous condenser capacity is deployed when the modelled inertia cost is above its long run marginal cost. This results in the addition of ~10GVAs of new synchronous condenser by 2040 in the National BAU case. The other scenarios assume the same inertia requirements and same synchronous condensers capacity.

The remaining inertia requirements are met by other synchronous generators (i.e. CCGT, nuclear, hydro and pumped storage).

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We care about making future.

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