Public

REMA Scheduling and Dispatch Assessment

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NESO
National Energy System Operator

Contents

1. Introduction

This publication is to share the findings from our assessment of scheduling and dispatch reform options undertaken within the Review of Electricity Market Arrangements (REMA). This work was undertaken from 2024 to early 2025, prior to publication of the REMA Summer Update in July 2025.

The REMA programme considered a wide range of reforms that aim to address key challenges facing electricity markets, including passing through the value of renewables to consumers, ensuring sufficient investment at pace, transitioning to a flexible and secure decarbonised system, and operating a renewables-based system cost-effectively.

A central focus of the REMA programme was the new challenges that have emerged for operating the system as it has decarbonised, leading to rising balancing costs which ultimately fall on consumers. Balancing costs have increased from £1.2bn in 2018/19 to £2.7bn in 2024/25, and latest projections show that this could increase to around £4-8bn in 2030, depending on the delivery of new network build.[1]

To address these challenges, the REMA programme considered reform to dispatch arrangements, including assessing self-dispatch (e.g. Balancing Mechanism (BM) reform) and central dispatch, as well as considering changes to wholesale pricing. NESO supported the Department for Energy Security and Net Zero (DESNZ) in this assessment by leading the 'Dispatch' workstream.

2. Summary of our work on scheduling and dispatch reform

For the first stage in our scheduling and dispatch assessment, NESO worked with AFRY on the scheduling and dispatch 'Case for Change' to identify the limitations of the current arrangements in Great Britain (GB) and inform the development of alternative dispatch models. The work identified the following three key limitations of the current design:

- **Incentives**: The energy markets do not provide scheduling incentives in line with system needs and operational requirements.
- **Visibility and access**: Significant gaps in NESO visibility of market outcomes and intended positions of market parties, and limited access to some resources impacts coherence between wholesale market and balancing.
- **Intertemporal issues**: The current dispatch mechanism does not facilitate effective optimisation of costs and unit constraints over time.

[1] NESO Annual Balancing Costs Report (2025)
The £8bn in constraint costs is based on the expected network in 2030. The recommended network for Clean Power 2030 (which accelerates three network projects which have delivery dates after 2030) would reduce constraint costs to approximately £4bn.

With the case for change established, the next stage involved identifying possible solutions. Here, we identified three overarching strawman models for dispatch, each with variations according to pricing (national or zonal) or paradigm (SO access or market incentives).

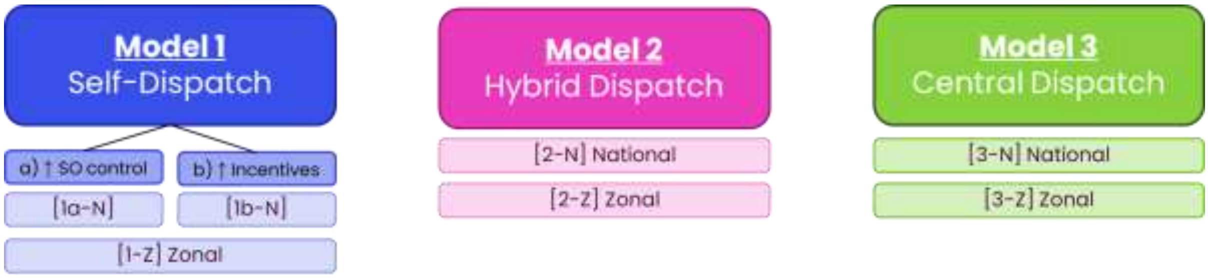

Figure 1: *Overview of dispatch models*

The models were intended to cover the spectrum of different scheduling and dispatch approaches undertaken world-wide, and to allow assessment of how suited they were to address the issues identified in the case for change. We shared this work with industry in July 2024.

3. REMA Summer Update

In July 2025, DESNZ published the REMA Summer Update which set out the policy outcome for REMA. DESNZ were considering two broad approaches for wholesale electricity market reform: zonal pricing, where the electricity market would be split into several zones to reflect the most significant (but not all) network congestion; or Reformed National Pricing (RNP), which would retain a single national price, alongside reforms to balancing arrangements and greater strategic planning.

DESNZ concluded that they will pursue RNP, and so will not introduce zonal pricing. As part of this, DESNZ committed to implementing a package of reforms to the existing arrangements, built around three interlinked pillars (i) reform siting and investment levers to deliver the Strategic Spatial Energy Plan; (ii) Improve system operability and efficiency; and (iii) Further bear down on network constraint costs.

4. How this work is being considered within RNP

The work we are publishing was completed prior to the decision to pursue RNP. With the programme of work completed, we are in a position to share with industry the analysis undertaken for our assessment of scheduling and dispatch options.

Central dispatch was a potential reform option explored as part of REMA. However, due to issues relating to deliverability and investor confidence, DESNZ adopted a minded-to position not to take forward central dispatch as part of the 2024 REMA Autumn update.

While central dispatch could lead to benefits for consumers through more efficient management of energy and system needs, it would be a substantive change and complex to implement. As such, alongside DESNZ and Ofgem, NESO will continue to explore a range of other dispatch reform options with a view to improving system operability and reduced costs for consumers.

This work provides a baseline understanding of the potential benefits of alternative scheduling and dispatch approaches, and the interactions with the wholesale market. Key implementation considerations for GB are provided, including how compatible such reforms are with cross-border trading arrangements.

The work has enabled the relative weightings and trade-offs of scheduling and dispatch reform options to be considered by policymakers, and the robustness of such designs under different scenarios. Critical assumptions and findings were identified and discussed in the GB context with both DESNZ and Ofgem.

The findings of these projects provide an evidence base for the case for scheduling and dispatch reform and provide novel quantitative and qualitative insights on electricity market design to support wider discussion beyond RNP.

However, the analysis does not consider the costs of implementing scheduling and dispatch reform, or potential revenue uncertainty for market participants which could impact the cost of capital. Hence, further analysis which takes into account these wider impacts would be required to inform decision-making on whether to progress with potential reform options.

5. Overview of scheduling and dispatch assessment

Our assessment of scheduling and dispatch options was split across three connected projects:

- **Assessment of co-optimisation of energy and ancillary services**[2]
  This work included a qualitative and quantitative assessment of co-optimisation in GB by FTI Consulting ("FTI"). It was complemented by a qualitative report by N-SIDE, detailing the technical and economic aspects of different design options for co-optimisation.
- **Assessment of self and central scheduling**[3]
  FTI quantitatively evaluated the impact of self vs central scheduling on consumer costs in GB and considered how potential changes to the BM and/or the introduction of zonal pricing would impact this evaluation.
- **Compatibility assessment of dispatch options with cross-border arrangements**
  This report by FTI explored how REMA reforms under consideration impact and interact with current and potential future cross-border trading arrangements.

[2] Here, co-optimisation refers to the simultaneous clearing of energy and ancillary services markets, while accounting for their interdependencies, as opposed to sequential procurement today.
[3] FTI use the term central scheduling, i.e. the running of a Security-Constrained Unit Commitment (SCUC) model at the day-ahead stage to determine instructions to market participants in that timeframe. The purpose is resolving forecasted violation of thermal limits of the network that would result under the "unconstrained" day-ahead wholesale market schedule. With central scheduling, FTI intends the same as what is referred to as central dispatch throughout the REMA consultations.

Key findings

The following is a summary of the key findings from all three projects. For detail on the modelling methodology, deeper explanation of the results, and further qualitative discussion, please refer to the full reports.

A summary of the consumer benefits of each model tested is shown in the table below. Please note, the co-optimisation and core scenario results are presented in 2022 real terms, whereas the updated scenario is in 2024 real terms. Results shown in brackets have been scaled to 2024 prices to enable a fair comparison between the core and updated assessments.

Table 1: Consumer benefits of self and central dispatch, 2030-2040, NPV

Wholesale pricing	Dispatch mechanism	Consumer benefits - Core scenario[4]	Consumer benefits - Updated scenario [5]
National	Self-dispatch with augmented BM	£2.5bn	-
	Central dispatch	£8.2bn (£8.8bn)	£1.9bn
Zonal	Self-dispatch	£14.6bn (£15.6bn)	£15.1bn-£26.1bn
	Central dispatch	£18.2bn	-

Table 2: Consumer benefits of co-optimisation of energy and ancillary services, 2025-2035, NPV

Scenario	Wholesale pricing	Dispatch mechanism	Consumer benefits
2025-2035	National	Co-optimisation of energy and ancillary services	£4.9bn

Dispatch reform under national pricing

- The consumer benefits of central dispatch are a function of:
  - *Transmission constraints*
    - ➔ Higher constraints increase the benefits of central dispatch
  - *Renewables/demand forecast errors*

[4] The core scenario generation background is FES 2022 Leading the Way with the HND + NOA7 Refresh network.
[5] The updated scenario generation background uses a combination CP30 Further Flex and Renewables and FES 2024 HT, with the Beyond 2030 network.

➔ Higher forecast errors increase the benefits of self-dispatch[6]

- From this, FTI test the key trade-off between self- and central dispatch: whether it is more beneficial to (1) resolve transmission constraints at day-ahead under central dispatch or (2) to allow the market to resolve energy imbalances that emerge from forecast errors through unconstrained trading under self-dispatch, with transmission constraints being left to resolve post-gate closure.
- In the core scenario, FTI found that moving from self-dispatch to central dispatch under national pricing could deliver £8.2bn in 2022 prices (£8.8bn in 2024 prices) of consumer savings for the period 2030-2040, representing a 23% reduction in balancing costs.
- This suggests that in the modelled scenario, solving transmission constraints at the day-ahead stage under central dispatch provides better consumer value than allowing unconstrained trading between market participants to resolve energy imbalances, even with improvements to the BM.
- This occurs from access to a broader range of generators (e.g. those with longer lead times) and a reduction in the cost to reposition ICs (and other flexible assets), which would reduce the reliance on more expensive actions nearer to real-time.
- Retaining self-dispatch but with an augmented BM (greater competition due to a wider range of technologies in the BM and improved utilisation of storage assets) could provide £2.5bn (or 7%) of savings over the same time period, compared to the status quo arrangements.
- Overall, the quantitative analysis found that while BM reform would, in itself, be welfare-enhancing for consumers, the consumer benefits of introducing central scheduling would be greater.

Co-optimisation of energy and ancillary services (response and reserve)

- This analysis compared (a) the status quo arrangements, where energy and ancillary services are procured independently (and 'sequentially'), meaning that resources need to make an upfront choice as to which market to participate in, relative to (b) an alternative arrangement where energy and ancillary services are 'co-optimised'.
- Under co-optimisation, the clearing of energy and ancillary services markets occurs simultaneously, which produces a more efficient allocation of resources across all markets, and more efficient price signals in those markets.
- If central dispatch[7] and national pricing is combined with co-optimisation of energy and ancillary services, a further £4.9bn of consumer savings could be unlocked over an 11-year period, according to FTI.

[6] The modelling conservatively assumes that under central scheduling there would be no intra-day trading to resolve forecast errors after the day-ahead stage (whereas under self-dispatch the model assumes all forecast errors are resolved via intra-day trading). This is discussed in more detail below.

[7] For modelling purposes, both 'sequential' and 'co-optimised' arrangements were undertaken under the assumption of central dispatch being in place. This enabled FTI to isolate the impact of co-optimisation alone. As already discussed, the merits of central dispatch were also evaluated quantitatively. In this sense, the benefits of co-optimisation should be seen as incremental to the benefits of central dispatch discussed above.

- The results show that co-optimisation could also improve the co-ordination of storage assets across energy and ancillary services markets, which reduces the need to run more expensive (and carbon intensive) fossil fuel units.

Co-optimisation in the context of decarbonisation

- As the electricity system decarbonises, N-SIDE found that the case for implementing co-optimisation is likely to be enhanced.
- This is driven by the scale and impact of opportunity cost forecast errors which are likely to increase due to:
    - Further deployment of intermittent generation contributing to more volatile prices.
    - Increased need for (numerous and interdependent) ancillary services to manage growing system operability challenges.
    - Higher complexity of a more interconnected and decentralised system.

Impact of higher transmission build-out on case for central dispatch

- In the updated scenario, which assumes a significantly higher transmission build-out, the consumer savings of central dispatch decrease to £1.9bn (this analysis does not consider the additional consumer costs of said transmission build-out).
- FTI explain that this is a result of reduced network constraint costs under national pricing and self-dispatch due to the more ambitious transmission build, and a higher magnitude of RES forecast errors (driven by a ~10% larger renewable build-out).
- Therefore, central dispatch provides even greater consumer benefits when transmission deployment does not keep pace with RES expansion.

Intra-day trading under central dispatch

- The assessment of central dispatch conservatively assumes no intra-day trading to resolve forecast errors at the day-ahead stage (whereas under self-dispatch the model assumes all forecast errors are resolved via intra-day trading).
- Implementing an intra-day trading solution under central dispatch (likely easier facilitated via intraday auctions) would further increase the consumer benefits, as forecast errors are the key driver of consumer costs under central dispatch.
- For reference, the cost of resolving forecast errors totals £7.9bn over the 11-year period in the core scenario.

Investor confidence and central dispatch

- Due to the mismatch between nodal scheduling under central dispatch and compensation based on a national price, transfer payments are likely to be required to compensate units under certain conditions.
- While such transfers would ultimately be a policy decision (alternative designs could increase the consumer benefits of central dispatch, however, potentially undesirable

bidding behaviour that could arise under such an approach would need to be examined), the analysis assumed that the following transfer payments would be put in place:

  - Firm access
    Asset is not centrally dispatched, but would have been under self-dispatch
  - Cost recovery
    Asset is centrally dispatched, but the national price does not cover its start-up and/or short-run marginal cost

- Assets are 'made-whole' under central dispatch with transfer payments, minimising impacts on investor confidence from central dispatch, while the consumer benefits still outweigh such payments in all scenarios.

Interactions with wholesale market reform

- Central dispatch implemented jointly with zonal pricing could provide consumer savings of £18.2bn under the core scenario over an 11-year period, which is the highest consumer savings under all modelled options in this scenario.
- The majority of this benefit would be driven by zonal pricing, which accounts for £14.6bn of the total savings. Introducing central dispatch in addition could provide a further consumer saving of £3.6bn.
- This indicates that zonal pricing would increase consumer benefits of central dispatch, but that the benefits of central dispatch arise regardless of whether national or zonal pricing is in place.

Cross-border trading and central dispatch

- The work on cross-border arrangements examines different combinations of central and self-dispatch, national and zonal pricing and explicit, implicit and Multi-Region Loose Volume Coupling[8] (MRLVC) cross-border arrangements (for full details of the combinations examined, please refer to the full reports).
- Other things being equal the analysis found that more granular locational signals and more implicit (rather than explicit) allocation of cross-border capacity would lead to efficiency improvements. These two dimensions have therefore been the focus of the analysis.
- FTI found that the first-best solution involves scheduling interconnectors based on the price at the transmission node (GSP) where the asset is connected; these prices are used under central dispatch to schedule all assets and are referred to as shadow nodal prices.
- However, the above approach is not currently feasible alongside price coupling market arrangements with Europe in the short to medium term due to computational and governance reasons.

[8] MRLVC is a form of Volume Coupling, which was set out in the Trade and Cooperation Agreement ("TCA") between the United Kingdom and the European Union as the basis for post-Brexit electricity trading between GB and the EU at the DA timeframe. For the purposes of this study, FTI were provided with a working assumption on the design of MRLVC.

- The remainder of the work therefore examined alternatives to this first-best approach (noting that the status quo arrangements with national pricing, self-dispatch and (mostly) explicit cross-border arrangements were found to be the least attractive combination possible).
- Alternatively, scheduling interconnectors based on shadow nodal prices appears to be feasible with explicit trading or Multi-region Loose Volume Coupling (MRLVC).
- Price coupling[9] is in principle compatible with scheduling interconnectors using a national wholesale price under central dispatch, but it would significantly reduce the potential benefits, relative to scheduling ICs based on shadow nodal pricing (combined with explicit arrangements or MRLVC).

Cross-border trading and zonal pricing

- A zonal market design can be combined with price coupling, without leading to significant costs. While zonal prices are less reflective of GB system requirements compared to shadow nodal prices, they produce more efficient outcomes than a national price. This would be reflected in reduced volumes of redispatch actions required to take place on Interconnectors under a zonal market design.

6. Conclusion

The assessment found that central dispatch could increase consumer welfare, relative to self-dispatch. This applies under both national and zonal pricing, and the cross-border arrangements (with suitable adjustments). However, there could be a reduction in benefits if implemented under explicit cross-border trading or MRLVC. Central dispatch unlocks the opportunity to introduce energy and ancillary services co-optimisation, which could provide further consumer benefits. Retaining self-dispatch with reforms to the BM, while delivering some improvements, were found to bring less benefits to consumers.

We would like to thank industry for the continued engagement with our work on scheduling and dispatch reform. The input and feedback have increased our understanding of the issues with the current market arrangements, shaped the development of our dispatch models, and supported a robust evaluation of potential reform options.

[9] Under Price Coupling: GB is assumed to be fully price-coupled with the Internal Electricity Market ("IEM") and effectively becomes part of Europe's Single Day- Ahead Coupling ("SDAC") and, under GB market designs with an ID timeframe, Europe's Single Intraday Coupling ("SIDC").