Public

NESO RIIO2 Business Plan 2 (2023-25)

February 2025 Incentives Report

25 March 2025

NESO
National Energy System Operator

Contents

Introduction

As part of the RIIO-2 price control, we submitted a second Business Plan to Ofgem in August 2022. It sets out our proposed activities, deliverables, and investments for years three and four of RIIO-2 (2023-2025) as we respond to the rapidly changing external environment.

The Business Plan 2 Delivery Schedule sets out in more detail what we will deliver, along with associated milestones and outputs, for the "Business Plan 2" period.

Ofgem, as part of its Final Determinations for the RIIO-2 price control, set out that we would be subject to an evaluative incentive framework, assessing our performance in delivering the Business Plan.

An updated guidance was published in September 2024 called NESO Performance Arrangements Governance (NESO PAG) Document. It sets out the process and criteria for assessing the performance of NESO, and the reporting requirements which form part of the incentives scheme for the remainder of the BP2 period. Every month, we report on a set of monthly performance measures; Performance Metrics (which have benchmarks) and Regularly Reported Evidence items (which do not have benchmarks). This report is published on the 17 working day of each month, covering the preceding month.

Every quarter, we report on a larger set of performance measures. Our eighteen-month report was similar to our usual quarterly report with the addition of providing an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker.

Our end of scheme report will be more detailed, covering all of the criteria used to assess our performance.

Following our Business Plan 2 (BP2) submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the BP2 DD&T investment portfolio. As per the NESO PAG guidance, we are required to provide quarterly reports directly to Ofgem as part of the CMF. We feel it is important to share updates with our external stakeholders and industry as part of the framework. So, we'll be including a summary of the CMF update every six months alongside our incentives reporting.

Please see our website for more information.

Summary of Notable Events

In February we successfully delivered the following notable events and publications. We provide further detail on each of these under the role sections:

- On 14 February, the BM registration process for participation in the Balancing Mechanism began moving to the Single Markets Platform (SMP). This transition involved two SMP deployments and a data migration exercise. Key benefits include visibility of BM registration data through SMP for self-service, automated communication of data to downstream BM systems, and potential enhancements through user feedback and integration with SMP APIs for aggregated Balancing Mechanism Units

- On 27 February, we held a Webinar to provide more information on our work to reduce skip rates. During this session we presented more details on our published data sets and the skip rate methodology, along with updates on our roadmap including key activities such as GC0166 and P462 delivery. Feedback from participants was positive, confirming that the session was useful and helped them understand better the new data that we are publishing on our portal.

- On 12 February, we published the A18 consultation to industry for Phase 2 of Quick Reserve. Please see the documentation in the 'QR Phase 2 Consultation' folder for more details. The consultation closed on 12 March and we will now consider all feedback prior to its publication to Ofgem.

- On 14 February, the DFS released a recorded webinar covering its performance since Ofgem approval on 21 November 2024, including key statistics, delivery volumes, performance metrics, savings, and participation breakdown. The project team announced plans for a bi-directional service. The recording received over 270 views in February. On 20 February, a live Q&A webinar addressed pre-submitted and on-the-day questions from the industry, with diverse topics covered.

- Following the successful go-live of the LCM in December 2023, we have sought feedback from stakeholders to enhance the product's value for consumers. Consequently, we have altered our approach to LCM procurement, which is expected to increase the average accepted price, with bids depending on daily market conditions. This aims to balance locking in cheaper options at a longer lead time versus waiting until real-time to minimise costs for end consumers.

- As part of the continuous improvement phase for the new EMR Portal, the Delivery Body collaborated with a Customer User Group to prioritise customer experience enhancements. In February, we met with the group to confirm proposed scope items for improvements expected in Q1 FY26 and demonstrated priority enhancements being implemented by the end of Q4 FY25. These changes were well received by the User Group. Supporting information is available on our NESO website.

- In February 2025, we submitted an updated proposal to the Connections & Use of System Code (CUSC) governance panel to introduce a proportionate Progression Commitment Fee for connections customers. This fee aims to ensure effective mechanisms for the success of Connections Reform. The proposal, informed by industry feedback from late 2024, includes the fee in future connection contracts if significant project capacities exit the reformed connections queue. It incentivises projects to progress and meet Clean Power targets. For more details, see New tool to drive connections queue progress proposed.

NESO Notable Events

Updated Independence Statement

On 17 February, we updated our Independence statement. This Independence Statement sets out how NESO complies with its independence licence obligations, and it is publicly available on our website.

To comply with our licence requirements, we have to show that various parts of our business are kept entirely separate.

The Independence Statement describes how NESO's governance is set up, how conflicts are managed and how we maintain our independence, including in regard to transitional services and other arrangements with our former shareholder (National Grid plc).

NESO Statement on Government Biomass announcement

On 10 February, as requested by the Department of Energy Security and Net Zero (DESNZ), we analysed the impact on Great Britain's electricity system covering the period 2027 to 2031, if bespoke support for large-scale biomass generation at Drax (2.5 GW capacity) and Lynemouth (0.4 GW capacity) was withdrawn from 2027.

Our analysis identified that having large-scale biomass available in this period could have a significant impact in mitigating potential risks to electricity security of supply and could also support the delivery of Clean Power by 2030. The analysis showed that without large-scale biomass, security of supply would not be ensured in scenarios with additional supply losses. While alternative options could deliver the same outcomes, these options have greater delivery risks.

The announcement from the Department for Energy Security and Net Zero is available on the Parliament Website and the outcome of the consultation on this issue is available on the Government's Website.

Summary of Metrics and RREs

The table below summarises our Metrics and Regularly Reported Evidence (RRE) for February 2025.

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£273m vs benchmark of £272m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 758MW vs indicative benchmark of 637MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 3.97% vs indicative benchmark of 4.73%	●
RRE 1E	**Transparency of Operational Decision Making**	94.7% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of NESO actions**	9.13 gCO_2/kWh of actions taken by the NESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 planned and 0 unplanned system outages	N/A

Below expectations ● **Meeting expectations** ● **Exceeding expectations** ●

We welcome feedback on our performance reporting to box.soincentives.electricity@uk.nationalenergyso.com

Carole Hook
Head of Regulation

Role 1

(Control Centre operations)

Metric 1A Balancing cost management

This metric measures NESO's outturn balancing costs (including Electricity System Restoration costs) against a balancing cost benchmark.

A new benchmark was introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark was derived using the historical relationships between those two drivers and balancing costs:

i. The benchmark was created using monthly data from the preceding 3 years.
ii. A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.
iii. A straight-line relationship has been established between historic non-constraint costs and the historic wholesale day ahead price of electricity.
iv. Ex-post actual data input into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used are as follows (with Day Ahead Baseload being the measure of wholesale price):

Non-constraint costs = 62.25 + (Day Ahead baseload x 0.478)
Constraint costs = -33.49 + (Day Ahead baseload x 0.39) + (Outturn wind x 23.51)

Benchmark (Total) = 28.76 + (Day Ahead baseload x 0.87) + (Outturn wind x 23.51)

**Constants in the formulas above are derived from the benchmark model*

NESO Operational Transparency Forum: We host a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our System Operations panel. Details of how to sign up and recordings of previous meetings are available here.

February 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

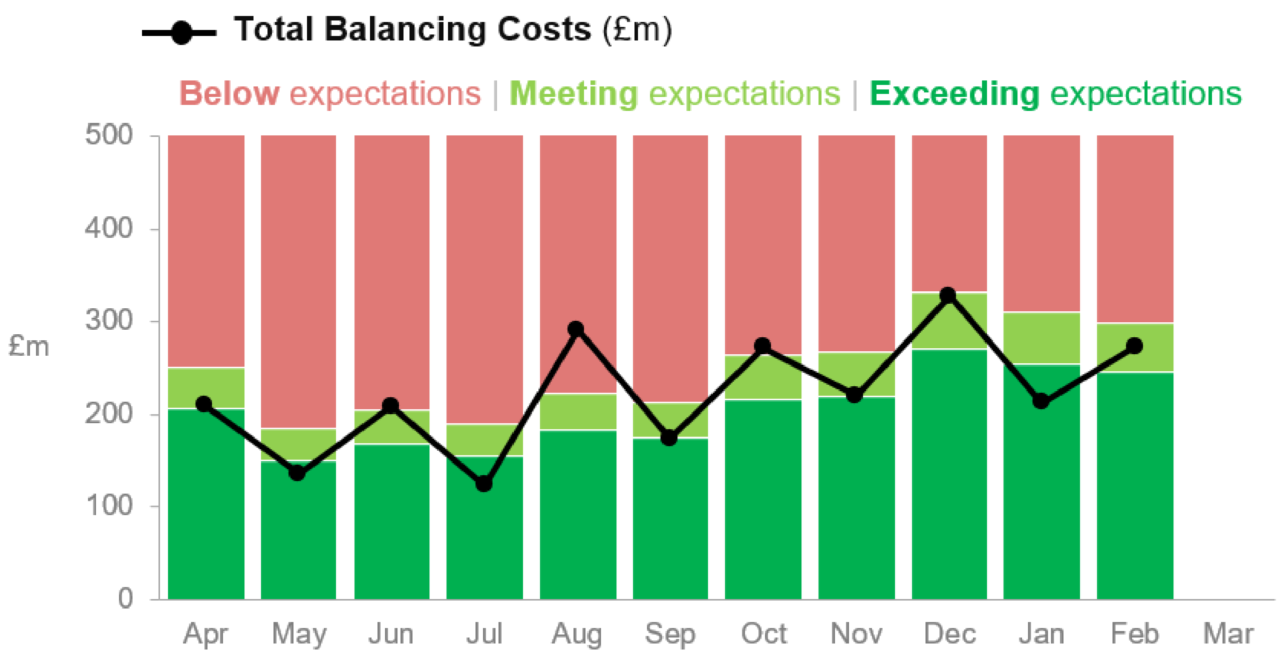


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	6.3	3.2	3.9	3.5	5.1	4.2	5.7	5.3	7.9	6.1	6.4		57.6
Average Day Ahead Baseload (£/MWh)	59	72	76	71	62	76	88	103	99	127	107		n/a
Benchmark	228	167	187	173	203	194	239	243	301	282	272		2488
Outturn balancing costs[1]	**209**	**135**	**208**	**123**	**291**	**173**	**272**	**220**	**327**	**212**	**273**		**2443**
Status	●	●	●	●	●	●	●	●	●	●	●		●

Previous months' outturn balancing costs are updated every month with reconciled values. Figures are rounded to the nearest whole number, except outturn wind which is rounded to one decimal place.

Performance benchmarks:

- **Exceeding expectations:** 10% lower than the annual balancing cost benchmark
- **Meeting expectations:** within ±10% of the annual balancing cost benchmark
- **Below expectations:** 10% higher than the annual balancing cost benchmark

Supporting information

BALANCING COSTS METRIC & PERFORMANCE

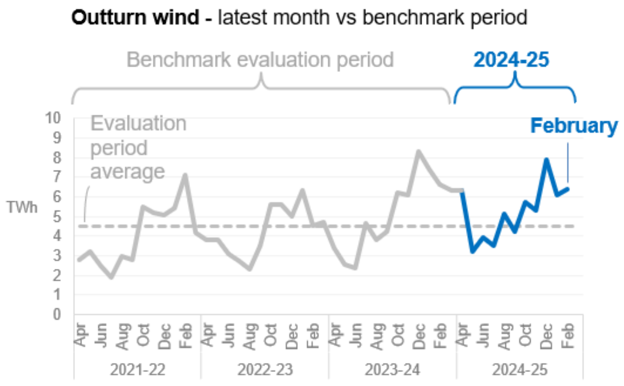
This month's benchmark

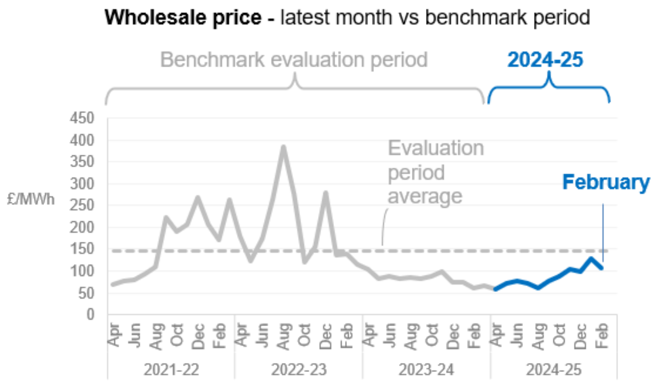
The February benchmark of £272m is £10m lower than January 2025 and reflects:

- An **outturn wind** figure of 6.4 TWh that is higher than the average of the current financial year (5.12 TWh) and slightly higher than last month's figure (6.1 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has decreased compared to January by roughly £20/MWh, but remains the second highest price so far in 2024-2025. However, February's wholesale price remains lower than the evaluation period average, but high relative to the rest of the year.

Lower wholesale prices contributed to a decrease in the overall benchmark compared to last month. Wind output remained fairly similar to January, implying that variations in the benchmark are solely associated with changes in wholesale prices.

[1] Outturn balancing costs excludes Winter Contingency costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.





Variable	February 2025	January 2025	February 2024
Average Wholesale Price (£/MWh)	**107**	**+20**	**-46**
Total Wind Outturn (TWh)	**6.4**	**-0.3**	**+0.2**
Benchmark (£m)	**272**	**+10**	**-28**
Performance	●	●	●

*The first three rows show the outturn measures for this month and difference in the previous month and same month last year, while the bottom row outlines outturn performance for each month.

Balancing Costs - Overview

The total balancing costs for February were £273m, which is £1m above the benchmark of £272m, and therefore performance is meeting expectations.

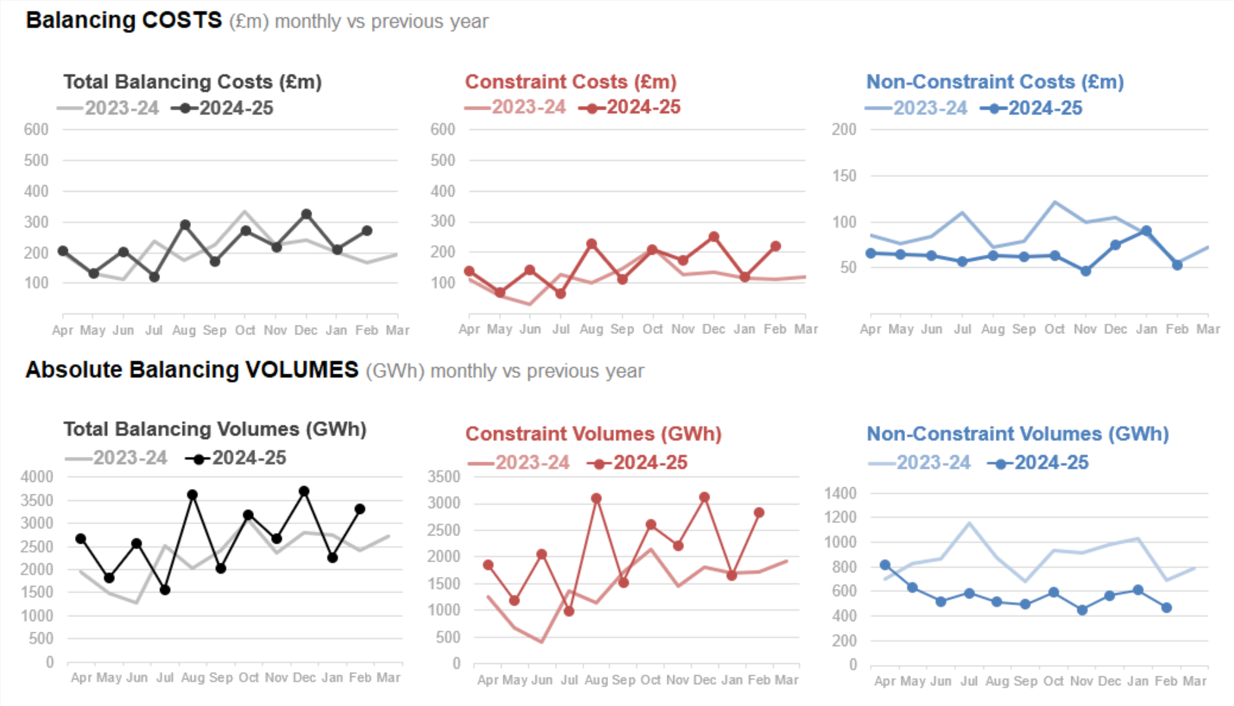
During February, the majority of balancing costs were associated with thermal constraints, primarily in Scotland and Cheviot, with some particular days linked to England and Wales constraints. The most expensive days of the month were characterised by high volumes of wind bids required to manage transfer limits in Scotland (B4, B5, B6) and Cheviot (B7). These costs, as has been common in recent months, have been exacerbated by multi-stage reinforcement works in the Scottish boundaries (taken as planned outages).

The most expensive day of the month was February 23rd, requiring up to 5,500 MW of wind bids during high demand periods to manage constraints in Scotland. Additionally, a hot joint was reported on an isolator at a substation in the South-East. This condition was aggravated by a nearby circuit in outage. The outage of the remaining circuit would have had significant implications for interconnectors and demand in the South-East. Flows were managed through Balancing Mechanism actions, primarily at thermal plants in the South-East, until the constraints were alleviated later that day with the return to service of the initial circuit.

February was also characterised by particularly low spending on voltage constraints, mainly because the commissioning of Greenlink has allowed access to an additional reactive capacity in the South-West (South-West England and South-Wales). Other resources that have been commissioned in other parts of the system (e.g., Pennines Pathfinder) have also contributed to this reduced spending on voltage management.

Overall constraint costs rose by £61m compared to the previous month, increasing £18.3m in England Wales and £69.5m in Scotland respectively (please note not all the cost components are included here, some of them reduced relative to last month).

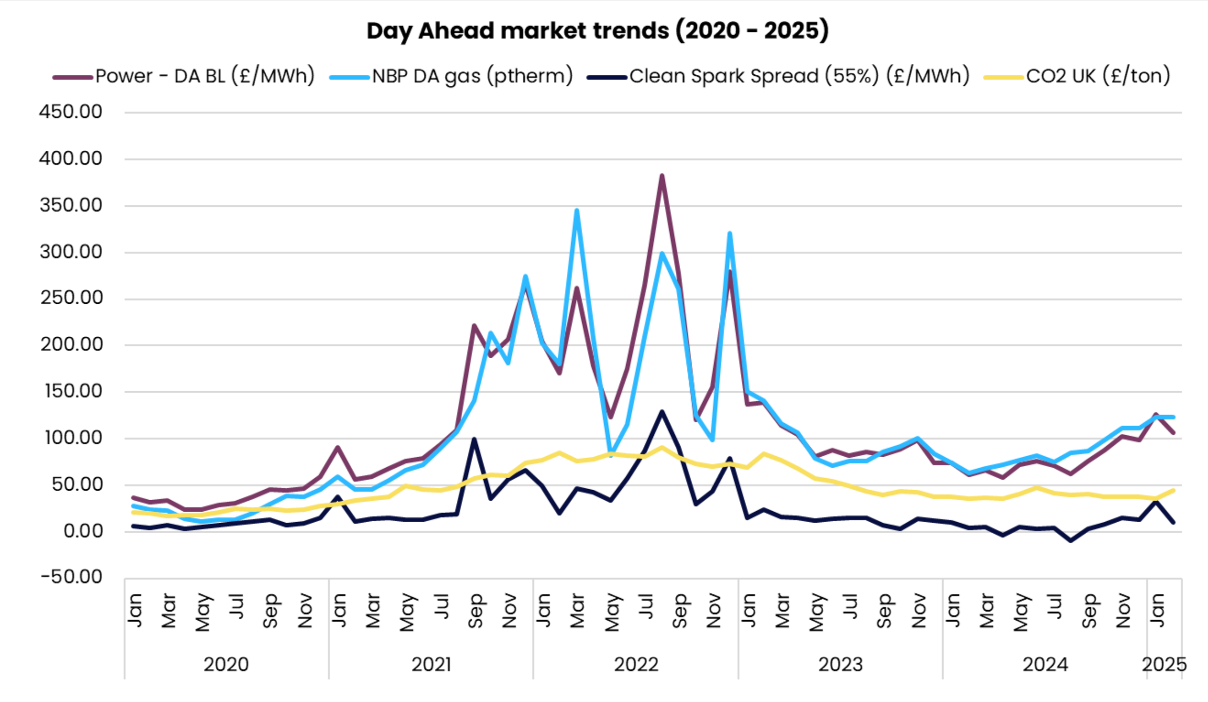
Average wholesale power prices were down £20/MWh compared to January 2025 but were higher by £45.8/MWh relative to February 2024. The volume-weighted average price for bids is £0.3/MWh, which represents a significant drop compared to last month's price of -£98.5/MWh. The volume weighted average price for offers decreased by £22/MWh (from £158.2/MWh to £136.2/MWh), in line with the monthly decrease in average wholesale price. Non-constraint volumes and costs have decreased by 139 GWh and £36m compared to January.



System and Market Conditions

Market trends

Power and gas prices fell compared to last month, with a subsequent decrease in the Clean Spark Spread Price and a slight increase in the CO_2 price. Power, gas and CO_2 prices remain higher compared to the same time last year. Lower prices have been supported by an increase in wind generation across the month and lower gas and power demand, driven by warmer temperatures.

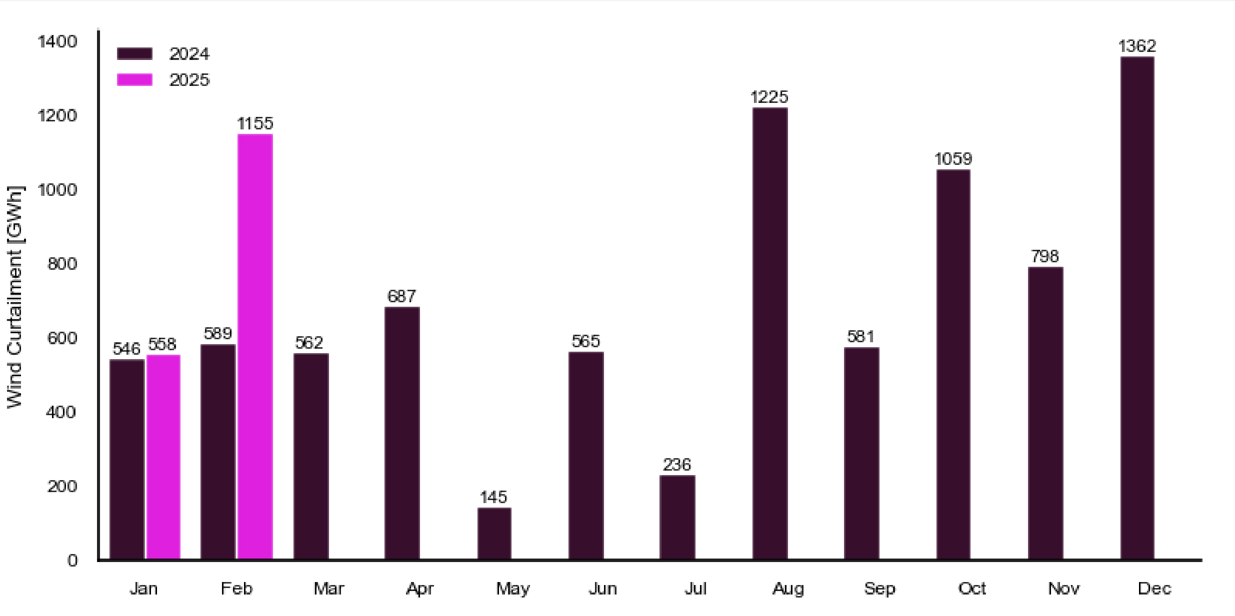


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Wind Outturn

February began with rain in western Scotland, before transitioning to more settled weather. The 23rd was the wettest and joint windiest day of the month.

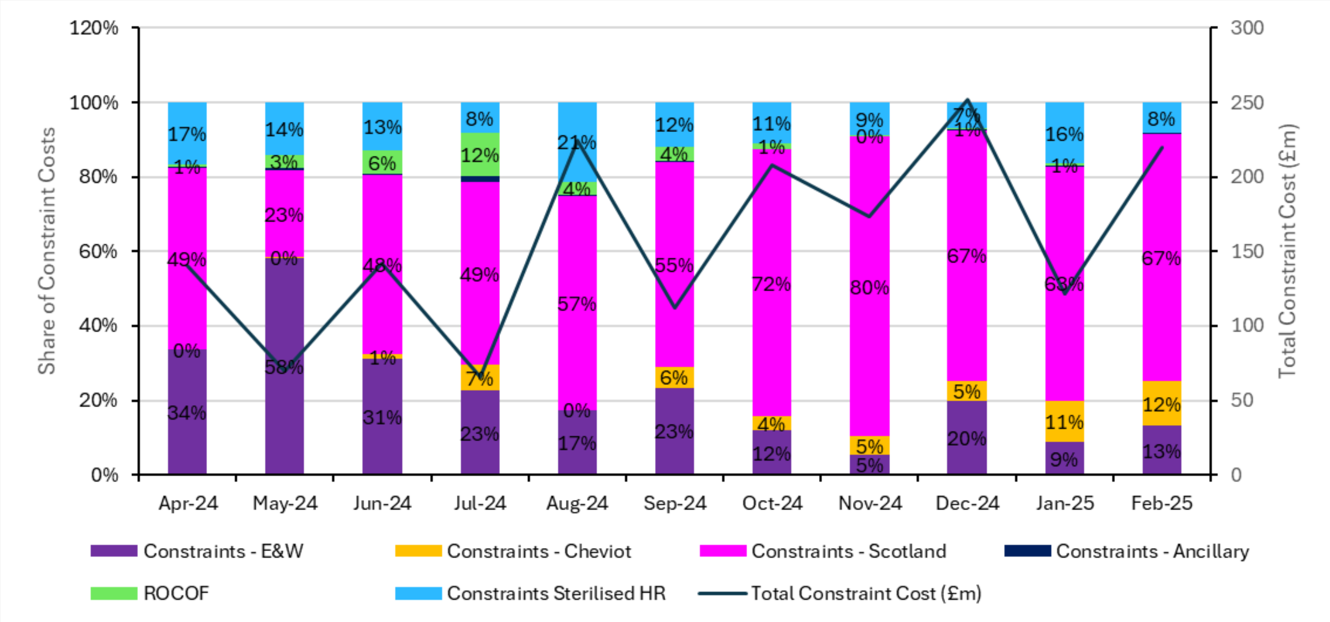
Overall wind outturn remained similar relative to last month, from 6.1 TWh in January to 6.4 TWh in February. England and Wales wind contributed with roughly 62% of total wind generation, whilst Scottish wind accounted for 38%. Similar contributions were observed during January (59% and 41% in England & Wales and Scotland respectively). The volume of wind curtailment increased from 558 GWh in January to 1155 GWh in February.



The highest wind curtailment for the month was seen on 23 February at 133 GWh, representing 29% of the hypothetical outturn. Reflecting active constraints at the Scottish boundaries.

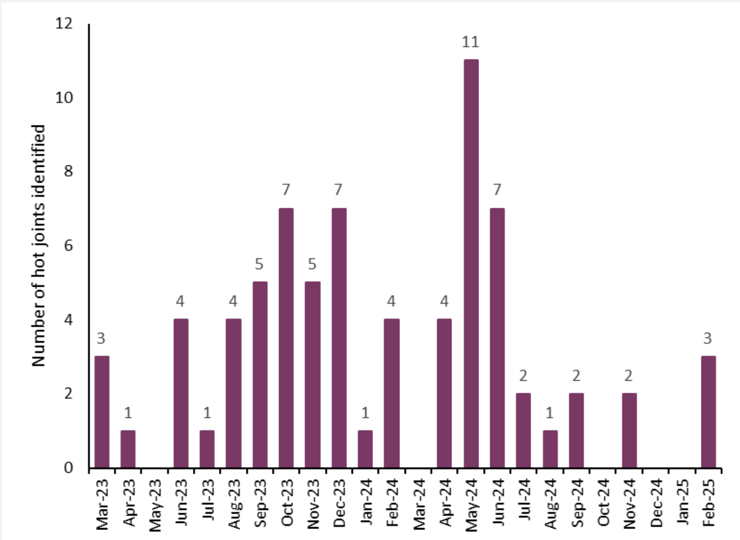
Constraints

Constraint costs in February increased by £97.8 million compared to January 2025. Scottish constraints were the main driver, which were responsible for 71% of the increase. These were at similar levels to those in October, November, and December 2024, characterised by higher-than-average wind output and a significantly impacted grid in Scotland due to various outages aimed at enhancing current transfer capacities. The main difference compared to January and the primary reason for the considerable increase in constraint costs is a significant rise in the volumes of curtailed wind. In January, 558 GWh were curtailed, while in February this value doubled to approximately 1155 GWh.



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. Three hot joints were reported during February, all of them in the South-East. At the moment we are still analysing the cost impact of the hot joints identified, particularly the one the 23rd that forced NESO to run thermal power stations in the South-East due to the downrate of specific equipment.



BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): February 2025 vs January 2025

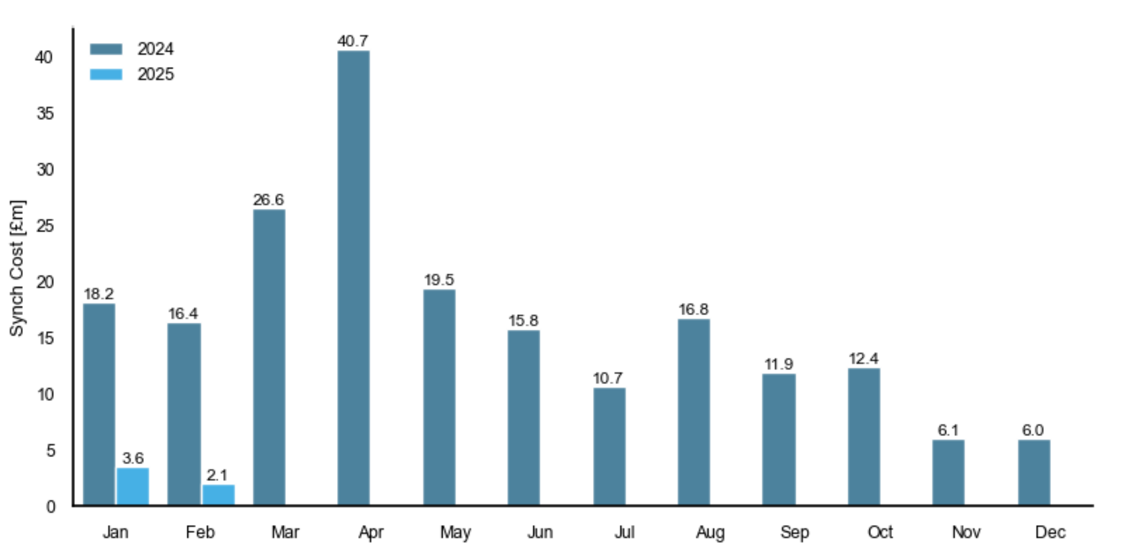
		(a) Jan-25	(b) Feb-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-3.9	-8.7	(4.7)	
	Operating Reserve	25.2	4.6	(20.7)	
	STOR	11.8	7.8	(4.0)	
	Negative Reserve	1.2	0.4	(0.7)	
	Fast Reserve	18.1	17.8	(0.3)	
	Response	20.3	17.9	(2.3)	
	Other Reserve	1.8	2.7	0.9	
	Reactive	11.4	10.5	(0.9)	
	Restoration	3.6	2.1	(1.5)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	0.4	-1.7	(2.1)	
Constraint Costs	Constraints - E&W	10.8	29.1	18.3	
	Constraints - Cheviot	13.4	25.9	12.5	
	Constraints - Scotland	76.7	146.3	69.5	
	Constraints - Ancillary	0.2	0.1	(0.0)	
	ROCOF	0.7	0.2	(0.6)	
	Constraints Sterilised HR	20.0	18.0	(2.0)	
Totals	Non-Constraint Costs - TOTAL	89.8	53.6	(36.2)	
	Constraint Costs - TOTAL	121.8	219.6	97.8	
	Total Balancing Costs	**211.6**	**273.1**	**61.5**	

As shown in the totals from the table above, constraint costs increased by £97.8m and non-constraint costs decreased by £36.2m, resulting in an overall increase in balancing costs of £61.5m compared to January 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£82m **Constraint – England & Wales: +£18.3m** **Constraint Sterilised Headroom: -£2m** Constraint costs increased by £97.8m in February, coinciding with a 1,172 GWh increase in the volume of actions. Wind outturn remained similar to last month, whereas wind curtailment increased 0.67 TWh, mainly impacted due to outages. **ROCOF: -£0.6m** In February, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in similar values relative to last month, from 28.4 GWh in January to 28.6 GWh in February.	**Constraints – Scotland & Cheviot: +£102.7m** **Constraints – England & Wales: +£9.7m** **Constraints Sterilised Headroom**: **-£2.6m** Constraint costs have increased by £106m compared to last year, aligned with a volume increase of 1,101 GWh. Wind outturn in February was around 0.2 TWh lower than February 2024, but power prices were significantly higher compared to last year. **ROCOF: -£3.2m** The expenditure on ROCOF tends to be marginal in the system. The implementation of the FRCR requirement reduction (140 GVAs to 120 GVAs) across February to June 2024 is contributing to reduced inertia volumes and costs compared to the previous year. Additionally, the commissioning of Stability Pathfinder Phase 2 assets is positively contributing to inertia levels in the system, resulting in minimal ROCOF spending.

Voltage – Monthly system cost of synchronisation actions for voltage control across 2024 and 2025:



Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support, depending on their location. In February, the system synchronisation costs (what it costs to the system, which factors in energy replacement, headroom among others) amounted to £2.1m, which is lower than the same period in 2024 (£16.4m).

Additional factors driving lower voltage management costs include:

- Commissioning of Greenlink interconnector (converter station +/- 172MVAr), providing additional voltage support in South Wales.
- Economic assets commissioned through voltage pathfinders. This includes the ones allocated in Mersey (a 38 MVAr battery at Capenhurst and a 200 MVAr reactor in Frodsham) and Pennines (reactors at Bradford West – 100 MVAr, Stocksbridge – 200 MVAr and Stalybride – 200 MVAr).
- Stability assets commissioned through stability pathfinders. Twelve synchronous compensators received contracts through Phase 1, providing roughly 12.3 GVA.s of inertia to the system, in addition to 1.06 GVAr of absorption and 950 MVAr of injection capacity.

Reactive Costs/Volumes

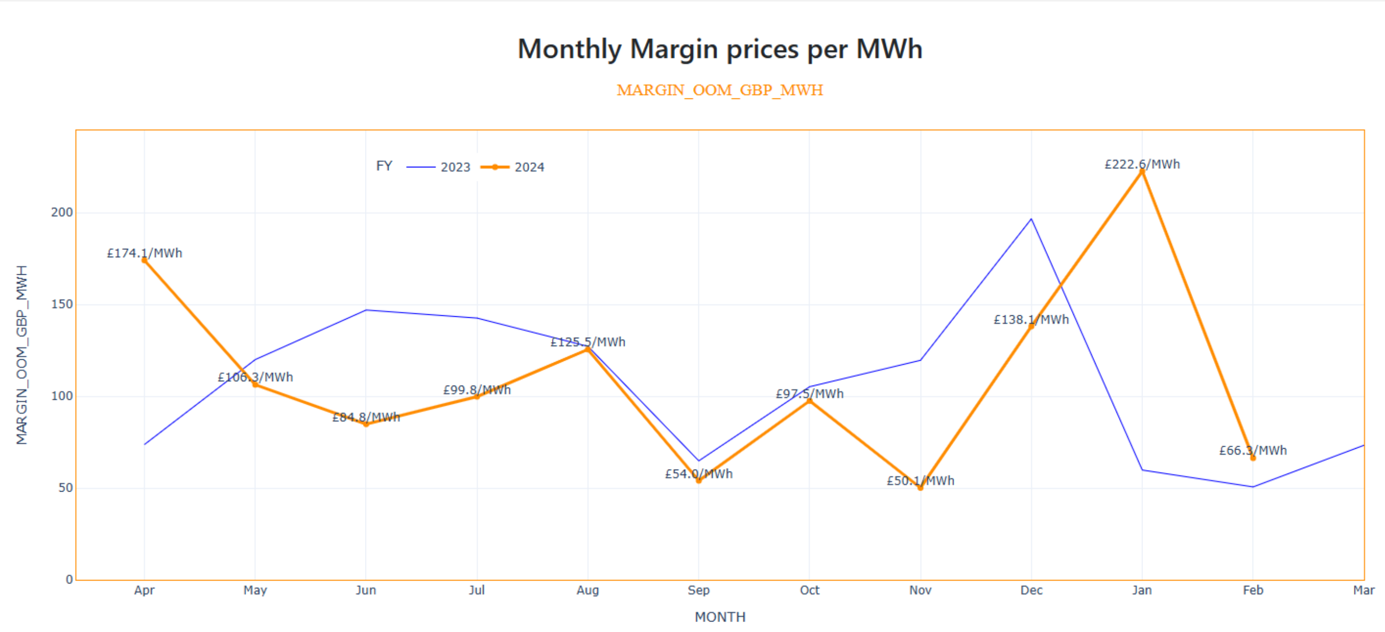
The volume-weighted average price for reactive power was £4.5/MVAr in February 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.9m The volume-weighted average price increased from £4.3/MVAr to £4.5/MVAr compared to last month.	**-£2.0m** The volume-weighted average price increased from £4.2/MVAr to £4.5/MVAr compared to last year.

We have started a Network Innovation Allowance (NIA) project that will review of the Obligatory Reactive Power Service (ORPS) methodology to ensure that the service remains fit for purpose and cost reflective.

Reserve Costs/Volumes

Reserve prices significantly decreased to £66.3/MWh in February from £222.6/MWh in January 2025.This is aligned with a decrease in the wholesale price month-on-month.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£20.7m **Fast Reserve: -£0.3m** There was a 356 GWh increase in the volume of Operating Reserve required to secure the system compared to January but decrease in margin prices over this period.	**Operating Reserve: -£1.6m** **Fast Reserve: +£3.5m** Margin prices were higher in February 2025 compared to the previous year, increasing from £50.6/MWh to £66.3/MWh.

Response Costs/Volumes

Our Dynamic Services for response, Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) continue to see the benefit of more competitive and more liquid markets and the continued development of the Single Market Platform.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£2.3m There was a 20.6 GWh increase in the volume of actions compared to January. Dynamic Containment, which makes up the majority of the volume procured from dynamic services, saw a reduction in clearing prices in January, supporting lower costs for the month.	**+£6.2m** The volume of actions taken for response increased 8.71 GWh compared to February 2024, aligned with higher clearing prices.

Dynamic Services Average Clearing Prices: February 2025 vs January 2025

		(a) Feb-25	(b) Jan-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.0	4.3	(0.3)	
	DM	5.5	3.6	1.9	
	DR	4.1	3.0	1.1	

Dynamic Services Average Clearing Prices: February 2025 vs February 2024

		(a) Feb-25	(b) Feb-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	4.0	1.2	2.7	
	DM	5.5	1.4	4.1	
	DR	4.1	1.4	2.7	

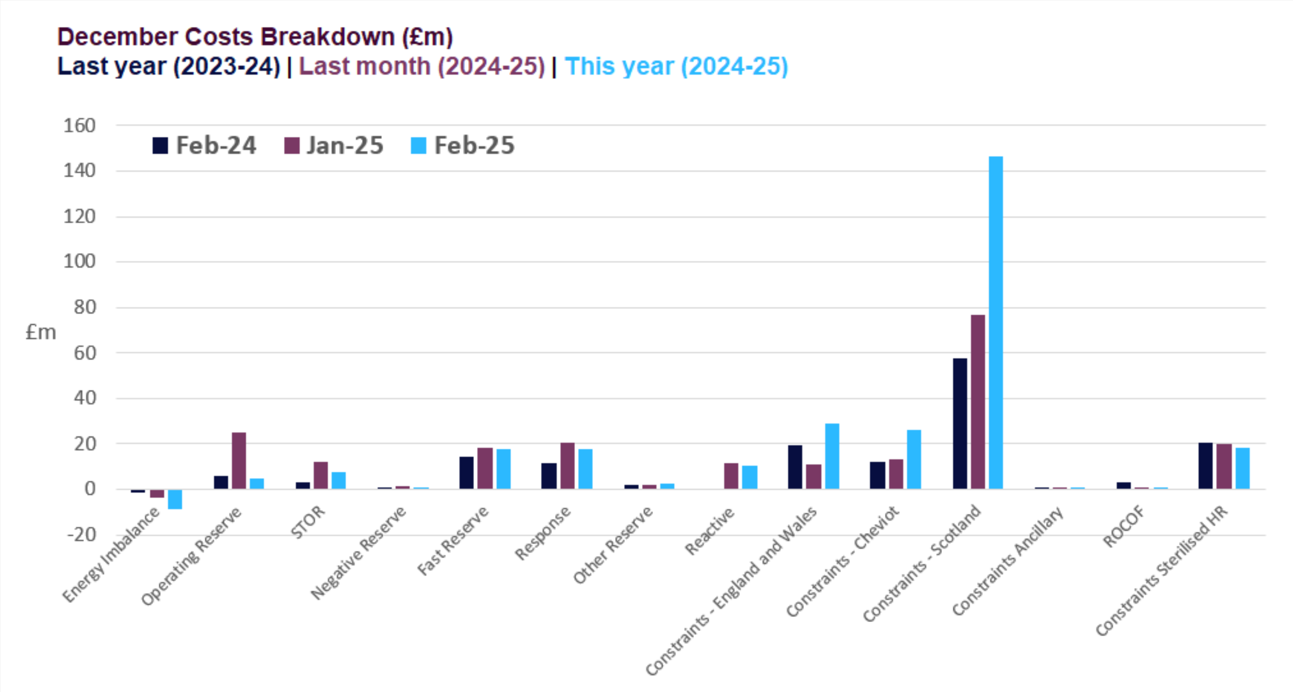
Average clearing prices for DC, DM and DR increased in February compared to January 2025 and February 2024. Frequency response revenues increased by 22% in February, as prices increased by 25% on average. The increased prices were largely due to higher Dynamic Moderation and Regulation prices, while Dynamic Containment prices fell. Frequency response prices are usually linked to wholesale prices and spreads, but moved in the opposite direction in February. This is because Dynamic Moderation and Regulation requirement volumes increased by 200 MW and 150 MW respectively. Dynamic Containment volumes remained unchanged, and so prices followed wholesale spreads.

Comparison breakdown

Constraint costs reduced by £97.8m compared to the previous month, this is due to an increase in both England and Wales (£18.3m decrease) and Scotland & Cheviot (£82m decrease), please note there are other constraint cost component which have decreased (e.g. ROCOF). However, constraint costs are up relative to last year, by £106m largely due to higher costs from Scottish constraints.

Non-constraints costs decreased by £36.2m from last month, largely driven by reduced spending on operational reserve (£20.7m reduction) and small deviations in other components. Non-constraint costs were £1.9m lower than February last year.

Thermal constraints currently dominate constraint costs. We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. The ongoing Review of Electricity Market Arrangements (REMA) is also considering options that could alleviate thermal constraints over the long term such as zonal pricing. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lowest cost.



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £25 million in February. This represents a reduction of around £30 million compared to January, where savings were £55 million. The most valuable action taken was the optimisation of the running arrangements at Waltham Cross substation (3-way split) which reduced the impact of outages within the area. This increased the transfer capacity of a constraint in the South-East by 2090 MW. The estimated cost savings for this action are close to £6 million.

Cost Savings – Trading

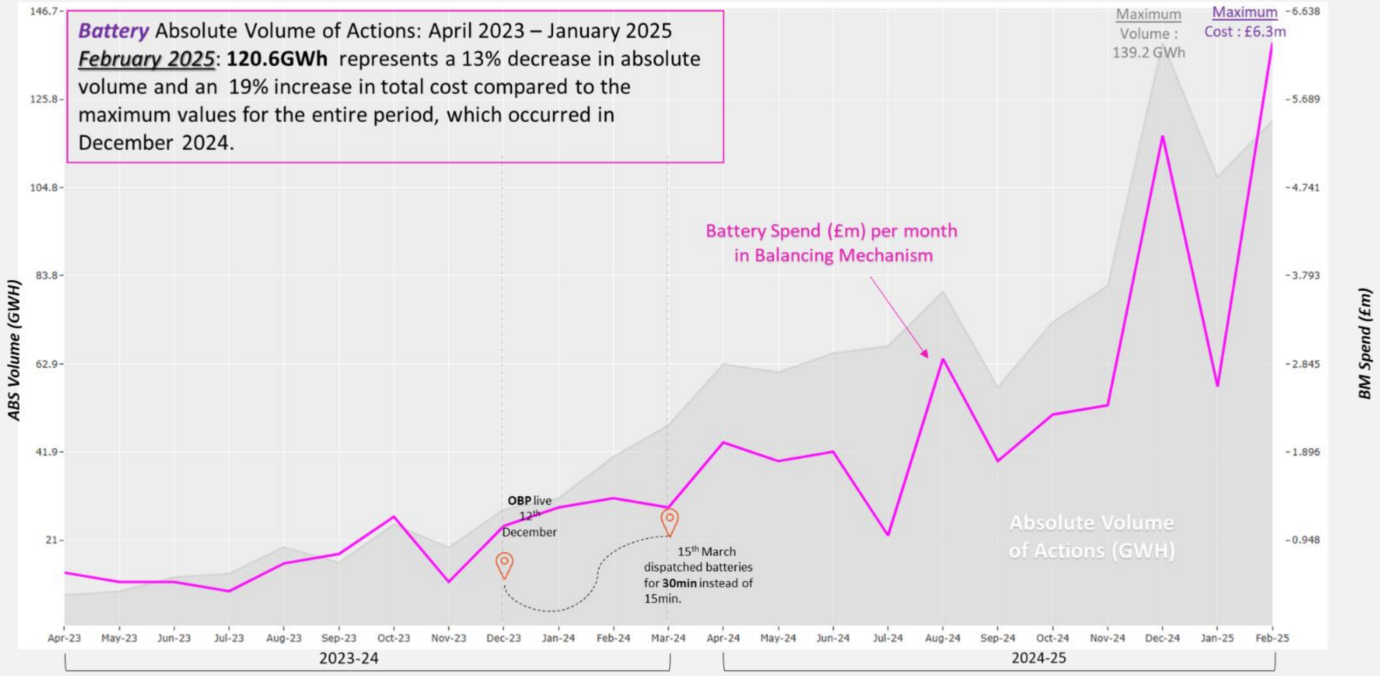
The Trading team were able to make a total saving of £8.1m in February through trading actions as opposed to alternative BM actions, representing a 9% increase on the previous month. Trading took place for voltage and constraints (especially the LE1 and B9 boundaries) with high winds being the main driver. Constraint trading over the month also aligned with a substantial amount of trading against Emergency Instruction (EI)/Emergency Assistance (EA) prices, with February seeing the third highest figure of trades against EI/EA in the last 12 months. The day with the greatest spend on trades was on the 4th February at a cost of £4.7m with the greatest component being for managing the LE1 constraint.

Cost Savings – Network Services Procurement (NSP)

We are using Network Services Procurement (NSP) to implement solutions to operability challenges in the electricity system. This includes the Constraint Management Intertrip Service, and Voltage & Stability pathfinders. We have calculated that the B6 and EC5 Constraint Management Intertrip Services, Voltage Mersey, and Stability Phase 1 have delivered approximately £292m in savings since April 2023. This represents the first set of live NSP projects, with savings for other live and future projects also undergoing development and implementation, such as Voltage Pennines and Stability Phase 2.

NOTABLE EVENTS

Monthly Absolute Volume of actions and spend for Batteries in the Balancing Mechanism
April 2023 to February 2025



The first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units (BMUs), the Open Balancing Platform (OBP), went live on 12 December 2023. Since then, our ability to dispatch a greater number of typically smaller BMUs within a settlement period has increased. This has unlocked greater capability to dispatch batteries in the Balancing Mechanism.

The total absolute volume of actions and costs have both increased compared to the previous month, January 2025. Battery dispatch increased and remained significantly higher than in earlier periods, at approximately 121 GWh. This illustrates our commitment to maximising the flexibility of energy provided by battery storage and small BMUs over the last year. Most of the spending on batteries was related to margin and minor components.

*An update in our database of the battery fleet had as result the updated graph and figures above.

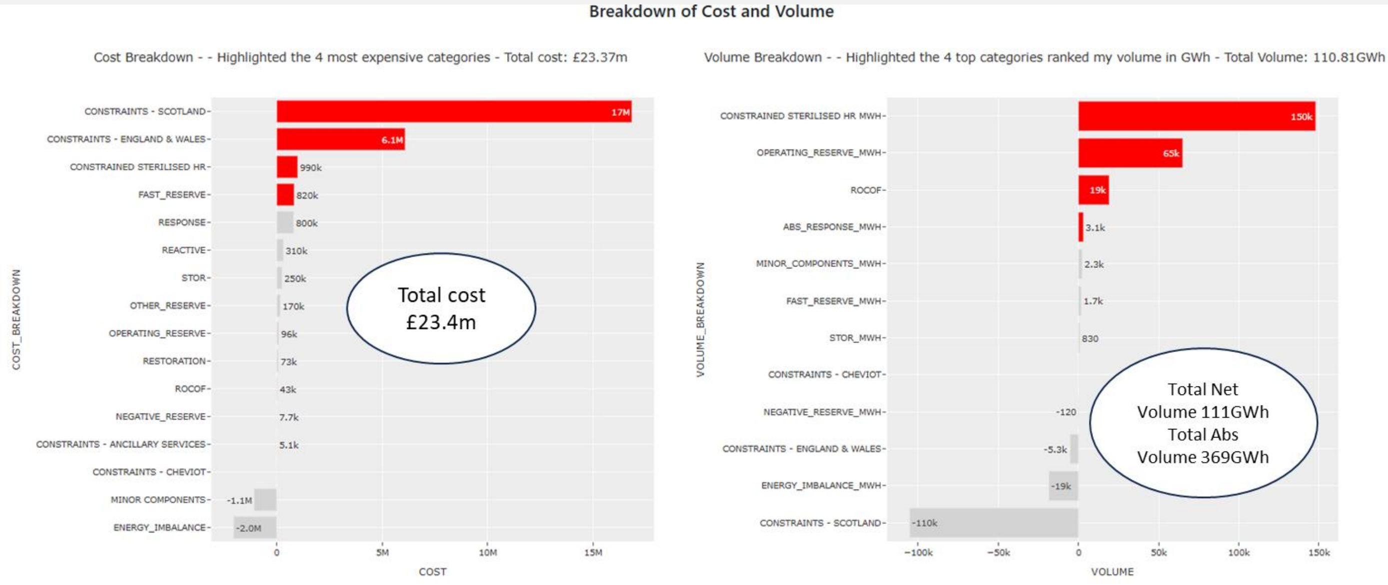
DAILY CASE STUDIES

Daily Costs Trends

February's balancing costs were £273m which is £61m higher than the previous month. Eight days were recorded with costs above £15m (23, 20, 3, 4, 21, 19, 24 and 22), with an additional three having a daily total cost over £10m (11, 18, 5 and 24). The daily average spending was £9.8m, increasing from £7.3m in January this year.

The lowest cost day was observed on 27 February, with a total balancing cost of approximately £2.3m. Generation on this day was largely met by self-dispatching plant. The highest cost day was 23 February, with a total spend of £23.4m. This day was characterised by Scottish constraints that were active throughout the night, which forced the curtailment of considerable volumes of wind, with bid prices accepted up to -392 £/MWh. This was mainly driven by thermal constraints. Additionally, some CCGTs were instructed for voltage management in the South-West (South-West England and South-Wales). Furthermore, a hot joint was observed at a substation in the South-East, which required actions in the Balancing Mechanism to manage flows.

High-Cost Day – 23 February 2025

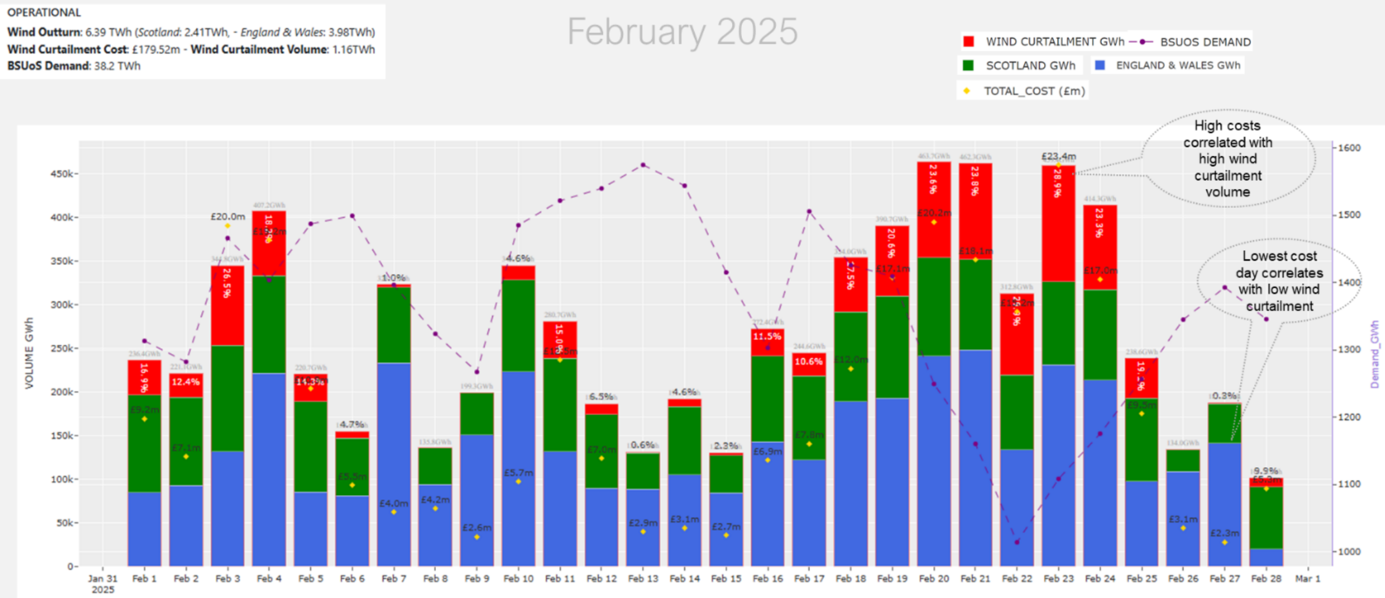


February Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

The chart below serves the purpose of supporting the transparency and the descriptions above. It is the daily "tour" of wind performance. With this graph we can trace, for example, how wind performance and low demand affect the cost of each day.

KEY:

Blue bars:	Wind generation in England and Wales
Green bars:	Wind generation in Scotland
Red bars:	Wind curtailment
Purple dotted line:	Demand resolved by the BM and trades
◆ Orange diamonds:	Daily cost



High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated NESO control room actions.

Metric 1B Demand forecasting accuracy

This metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

In settlement periods where the Demand Flexibility Service (DFS) is instructed by NESO, this will be retrospectively accounted for in the data used to calculate performance.

Performance will be assessed against the annual benchmark, but monthly benchmarks are also provided as a guide. The NESO will report against these each month to provide transparency of its performance through the year.

February 2024-25 performance

Figure: 2024-25 Monthly absolute MW error vs Indicative Benchmark

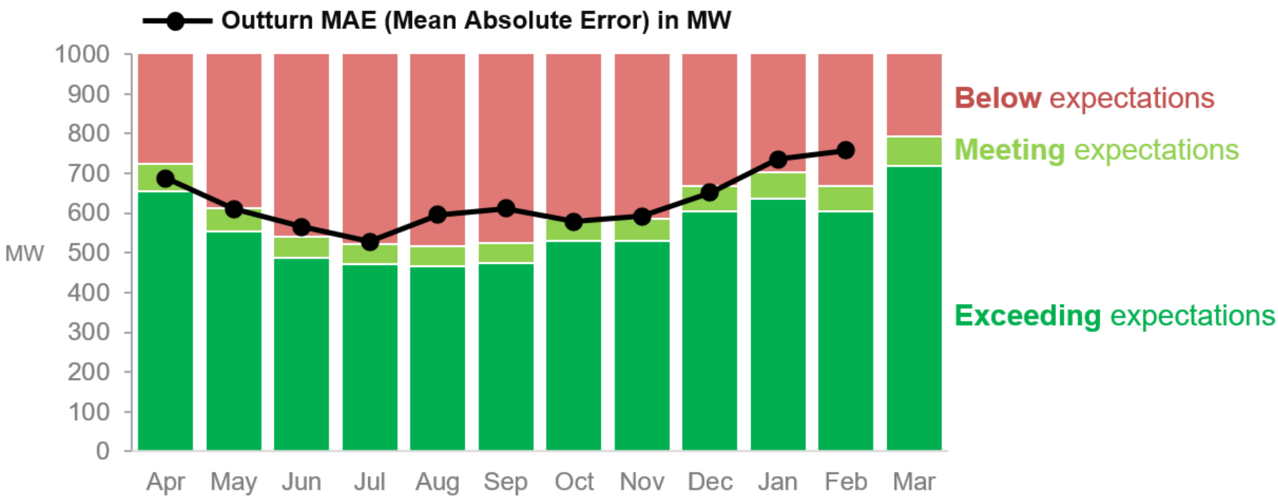


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	690	584	514	496	491	500	559	557	635	669	637	756
Absolute error (MW)	**687**	**610**	**565**	**528**	**596**	**612**	**578**	**591**	**652**	**735**	**758**	
Status	●	●	●	●	●	●	●	●	●	●	●	

Performance benchmarks:

- ● **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- ● **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- ● **Below expectations:** >5% higher than 95% of average value for previous 5 years

[2] Demand | BMRS (bmreports.com)

Supporting information

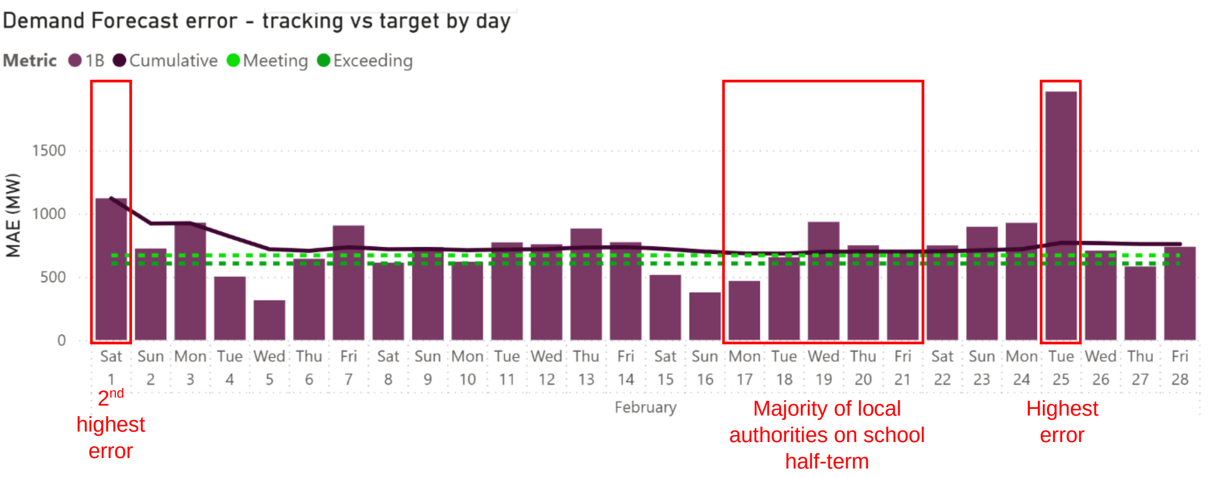
In February 2025, the mean absolute error (MAE) of our day ahead demand forecast was 758 MW compared to the indicative benchmark of 637 MW. The 5% range around this benchmark extends to 669 MW, meaning our performance failed to meet expectations for February.

February started gloomy and cold, then shifted to milder conditions mid-month with increasing temperatures and sunshine hours. Rainfall was below average, with settled conditions at the end of the month as well as widespread frost and some foggy conditions.

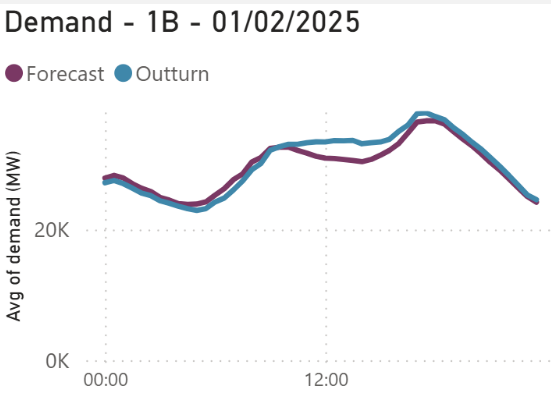
The shift in weather regime, as well as school half-term holidays, increased demand forecasting uncertainty. The machine learning model struggles to cope with such changing conditions..

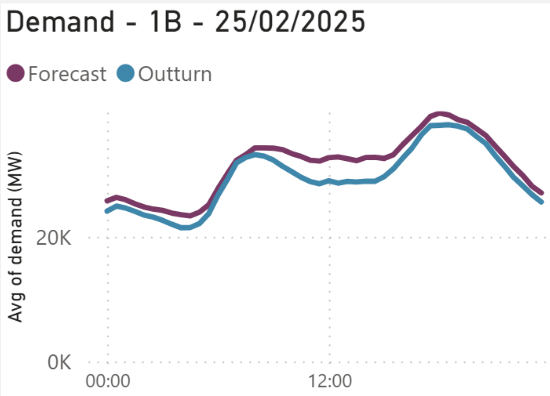
The largest demand forecast error this month was 4.2 GW on 25 February, settlement period 26.

Correcting for DFS, Demand peaked at 43.2 GW on 11 February, settlement period 36.



Below are details of the two days with the largest errors:





The distribution of settlement periods by error size is summarised in the table below:

Error greater than	Number of SPs	% out of the SPs in the month (1344)
1000 MW	374	28%
1500 MW	179	13%
2000 MW	82	6%
2500 MW	29	2%
3000 MW	15	1%

The days with largest MAE were 1st and 25th February.

Day	Error (MAE)	Major causal factors
1	1120	Underlying effects influencing demand, Solar forecast error
25	1964	Underlying effects influencing demand, plus poor guidance from the ML model

Missed / late publications

There were no occasions of missed or late publication in February.

Triads

Triads run between November and February (inclusive) each year.

Due to changes in charging methods, triads are expected to have a smaller effect than in previous years. However there may be other price related demand avoidance effects over the daily peaks.

Triad avoidance behaviour is predicted to have affected only one date in February: 11th February, totalling 1500MWh.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on February 3, 5, 6, 11, 12, 14, 17, 18, 19, 20, 24, 25, and 28, with a total of 1839MWh procured. These will affect the national demand outturn but are not included in the day ahead forecast.

Metric 1C Wind forecasting accuracy

This metric measures the average absolute error between day-ahead forecast (between 09:00 and 10:00, as published on NESO data portal) and post-event outturn wind settlement metering (as published on the Elexon insights portal) for each half hour period as a percentage of capacity for BM wind units only. The data will only be taken for sites that:

- did not have a bid-offer acceptance (BOA);
- did not withdraw availability completely between time of forecast and time of metering; for the relevant settlement period. We publish this data on its data portal for transparency purposes.

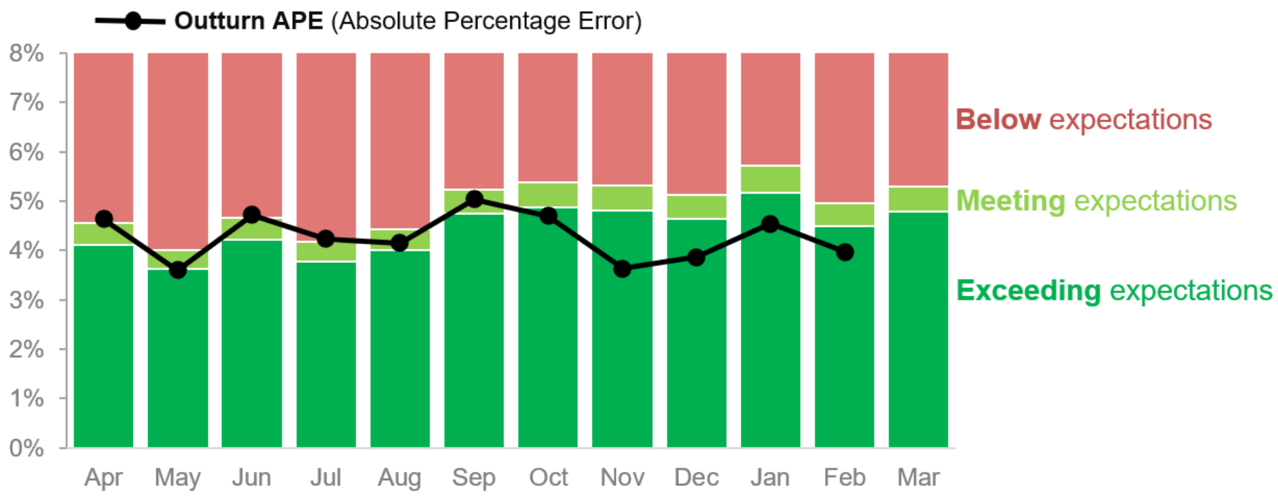
Sites deemed to have withdrawn availability are those that:

- re-declare maximum export limit (MEL) from a positive value day-ahead to zero at real-time; or
- re-declare their physical notification (PN) from a positive value day-ahead to zero at gate closure of the Balancing Mechanism.

The benchmarks are drawn from analysis of historical errors of the five years preceding the performance year. A 5% improvement in performance is expected on the 5-year historical average, with a range of ±5% used to set the benchmark for meeting expectations.

February 2024-25 performance

Figure: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmark



Change to methodology from 18-Month Report onwards

In line with the NESO Performance Arrangements Governance Document, from the 18-Month Report (published in October 2024), the APE% that we report excludes some of the factors that are outside of our control. This view excludes sites that have redeclared to zero and incorporates Initial Settlement Runs (+16 Working Days). This approach applies to the figures reported for the whole of 2024.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.34	3.82	4.45	3.98	4.22	4.99	5.13	5.07	4.89	5.44	4.73	5.05
APE (%)	**4.64**	**3.60**	**4.72**	**4.24**	**4.15**	**5.04**	**4.70**	**3.63**	**3.86**	**4.54**	**3.97**	
Status	●	●	●	●	●	●	●	●	●	●	●	

ESORI view of BMU Wind Generation Forecast APE (Previous Method)

Below, we report the APE% and benchmark based on the method described in The Electricity System Operator Reporting and Incentives (ESORI) Arrangements: Guidance Document. This applied prior to the transition to NESO on 1 October 2024, up to and including the figures reported in August 2024. This view includes sites that have redeclared to zero and does not incorporate Initial Settlement Runs (+16 Working Days).

A performance status is shown in the table below, however for the figures reported for September 2024 onwards, this is for information only and is not part of the 2024-25 incentives assessment.

Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks (ESORI method)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.32	3.85	4.43	4.02	4.19	4.98	5.13	5.02	4.93	5.46	4.74	5.09
APE (%)	**5.14**	**3.61**	**4.89**	**4.30**	**4.60**	**4.98**	**4.77**	**3.51**	**3.91**	**4.69**	**4.05**	
Status	●	●	●	●	●	●	●	●	●	●	●	

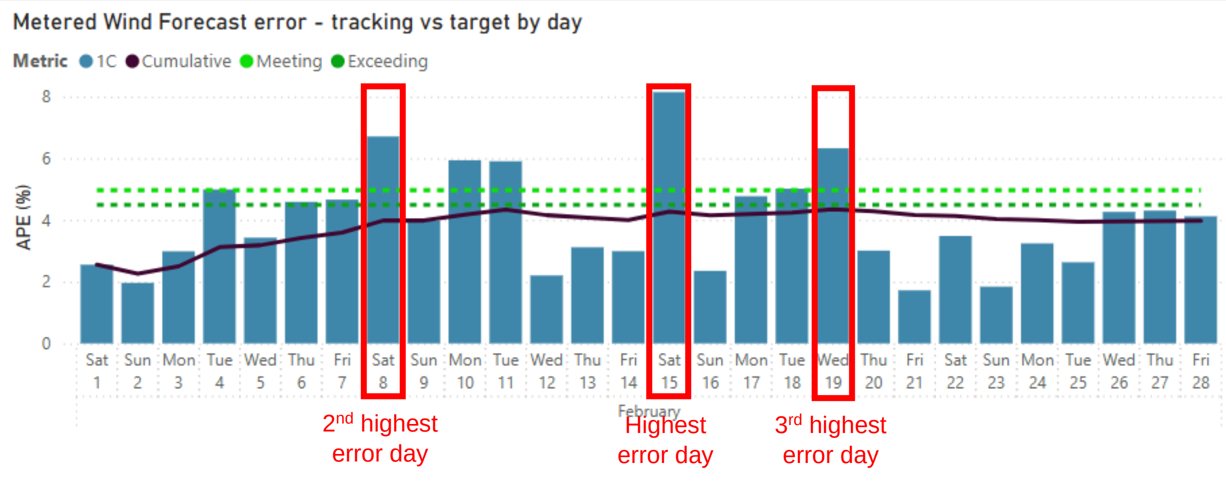
Performance benchmarks:

- ● **Exceeding expectations:** < 5% lower than 95% of average value for previous 5 years
- ● **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- ● **Below expectations:** > 5% higher than 95% of average value for previous 5 years.

Supporting information

In February 2025, the mean absolute percentage error (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 3.97% against the corresponding monthly benchmark of 4.73%. The 5% range around this benchmark extends from 4.49% to 4.97%, meaning our performance exceeded expectations for February.

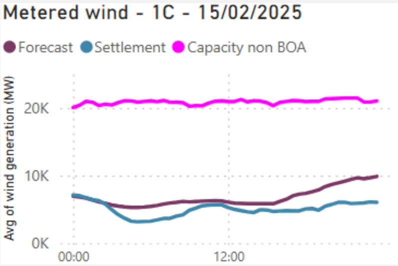
The met office reports February was "a quiet month with relatively little in the way of impactful weather, largely due to an extended period of anticyclonic conditions between the 6th and 19th." Stronger winds returned in the following week - with gusts of over 60mph - however, these conditions were well handled by our models. The month ended with another period of more settled wind.

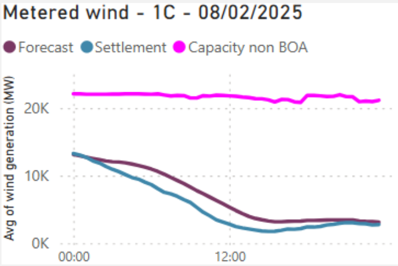


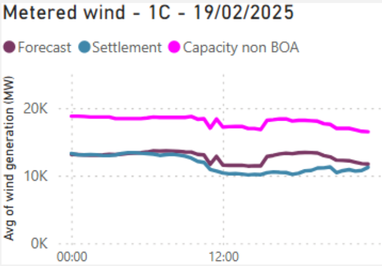
The largest forecast error this month was 3.8 GW on 15 February SP48. This was also the time of the largest APE which was 18.2%.

BMU wind generation peaked at 15.0 GW on 23 February.

Largest daily average errors







Details of largest errors

Day	Error (APE)	Major causal factors
15 Feb	8.15	Weather data (wind speed) error, particularly at the far end of the forecast period > 30hrs lead time
8 Feb	6.71	Weather-front timing-error
19 Feb	6.33	Weather data (wind speed) error, at the far end of the forecast period > 30hrs lead time

Missed / late publications

There was 1 late publication on the 6 February due to an IT failure.

RRE 1E Transparency of operational decision making

This Regularly Reported Evidence (RRE) shows the percentage of balancing actions taken outside of the merit order in the Balancing Mechanism each month.

We publish the Dispatch Transparency dataset on our Data Portal every week on a Wednesday. This dataset details all the actions taken in the Balancing Mechanism (BM) for the previous week (Monday to Sunday). Categories and reason groups are allocated to each action to provide additional insight into why actions have been taken and ultimately derive the percentage of balancing actions taken outside of merit order in the BM.

Categories are applied to all actions where these are taken in merit order (Merit) or an electrical parameter drives that requirement. Reason groups are identified for any remaining actions where applicable. Additional information on these categories and reason groups can be found on our Data Portal in the Dispatch Transparency Methodology.

Categories include: System, Geometry, Loss Risk, Unit Commitment, Response, Merit

Reason groups include: Frequency, Flexibility, Incomplete, Zonal Management

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions being taken out of pure economic order allows us to focus our development and improvement work to ensure we are always making the best decisions and communicating this effectively to our customers and stakeholders.

We have been publishing the Dispatch Transparency dataset since March 2021, and it has sparked many conversations amongst market participants. As we continue to publish this dataset for BP2 we will also be providing additional narrative to help build trust by explaining:

- actions we are taking to increase understanding of the NESO's operational decision making
- insight into the reasons why actions are taken outside of merit order in the Balancing Mechanism
- activity planned and taken by the NESO to address and reduce the need for actions to be taken out of merit order.

February 2024-25 performance

Figure: 2024-25 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

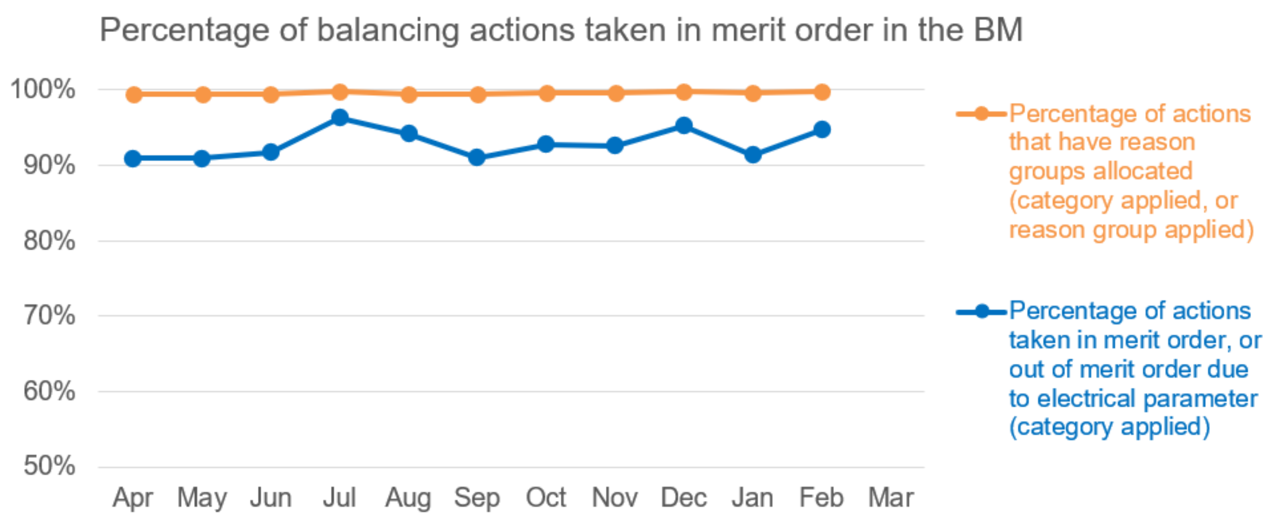


Table: Percentage of balancing actions taken outside of merit order in the BM

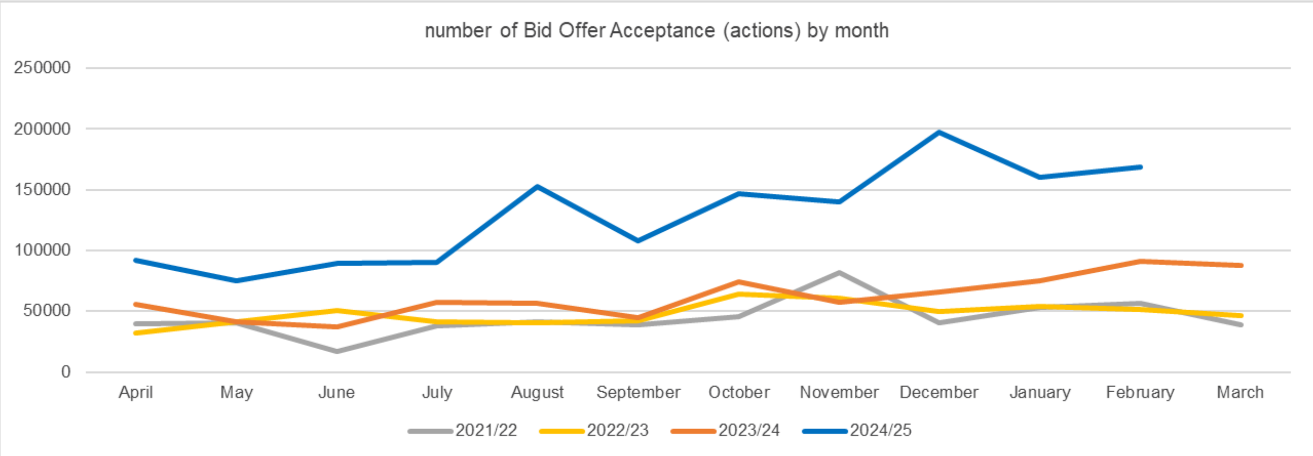
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	90.9%	90.9%	91.7%	96.3%	94.2%	91.0%	92.8%	92.6%	95.3%	91.4%	94.7%	
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%	99.5%	99.4%	99.6%	99.7%	99.8%	99.6%	99.8%	
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%	0.2%	0.5%	0.6%	0.4%	0.3%	0.2%	0.4%	0.2%	

Supporting information

February performance

This month 94.7% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 5.2% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months.

During February, there were 168,660 BOAs (Bid Offer Acceptances) and of these, only 257 remain with no category or reason group identified, which is 0.2% of the total.



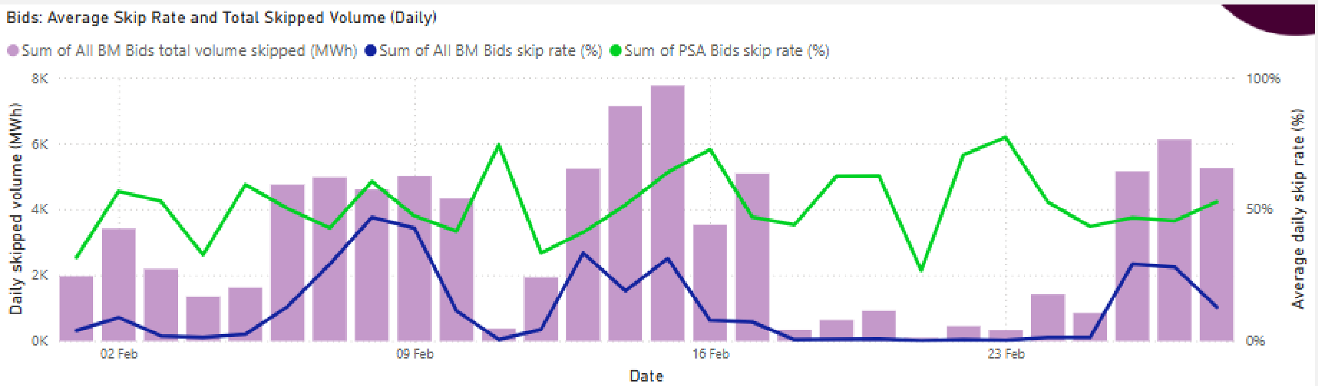
Other activities

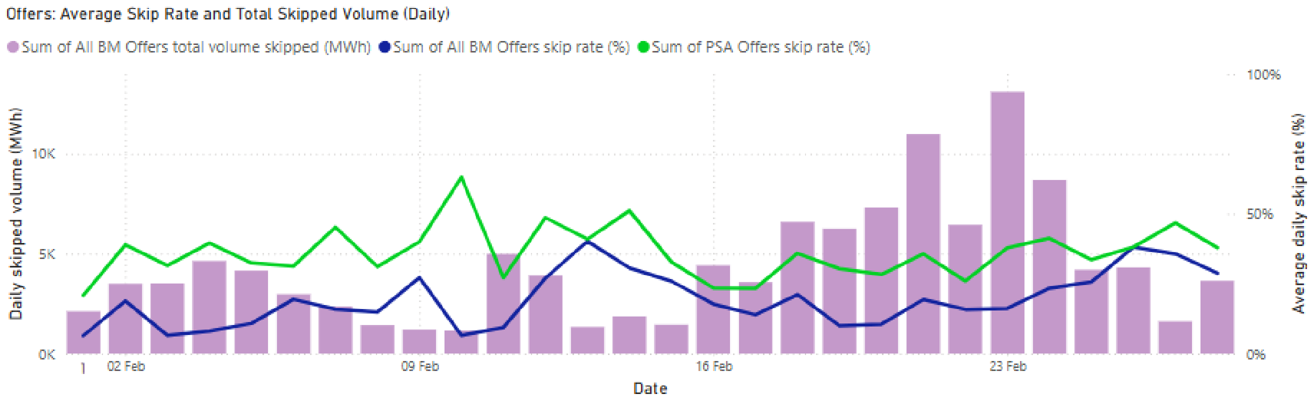
We hosted an industry webinar on 27th February on battery storage and skip rates. We summarised the skip rate methodology, discussed the 4 new datasets in more detail, and shared our roadmap for the next year. The slides and webinar recording are published on our website.

This is a summary of the average monthly skip rates for the two agreed definitions (All Balancing Mechanism & Post System Actions):

Monthly Average	Offers - All BM	Offers - PSA	Bids - All BM	Bids - PSA
January	18%	34%	11%	53%
February	15%	33%	5%	49%

The graphs below show daily skip rates and skipped volume for bids and offers in February.





RRE 1G Carbon intensity of NESO actions

This Regularly Reported Evidence (RRE) measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F (Zero Carbon Operability Indicator) and RRE 1G differs.

It is often the case that balancing actions taken by NESO for operability reasons increase the carbon intensity of the generation mix. More information about NESO's operability challenges is provided in the Operability Strategy Report.

February 2024-25 performance

Figure: 2024-25 Average monthly gCO2/kWh of actions taken by NESO (vs 2023-24)

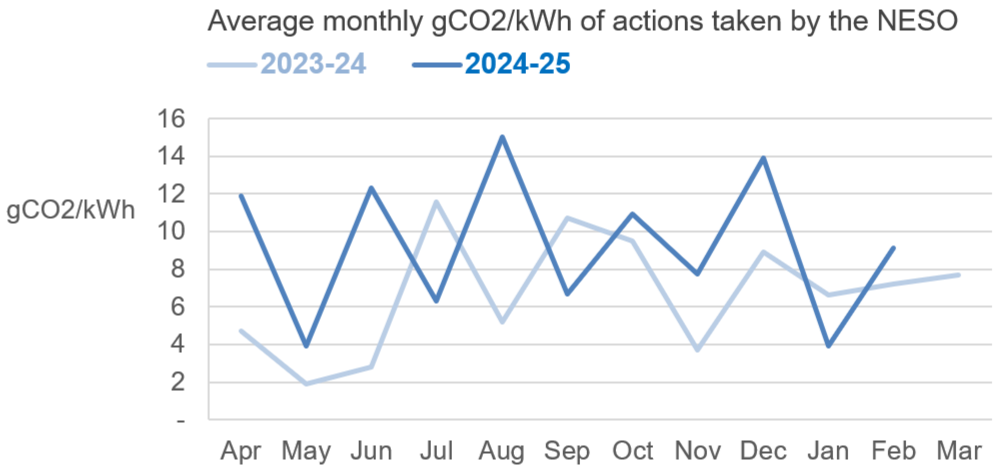


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31	6.33	15.02	6.69	10.92	7.74	13.92	3.91	9.13	

Supporting information

In February, the average monthly carbon intensity from NESO actions was 9.13gCO2/kWh. This is 5.22gCO2/kWh higher than January and 0.12gCO2/kWh lower than the 2024 YTD average of 9.25gCO2/kWh.

The maximum difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions applied was 47.68gCO2/kWh which took place on 23 February at 0330. This is 2.13gCO2/kWh higher than January's highest difference of 45.55gCO2/kWh.

From 19 – 23 February there was a consistent difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the BM and the equivalent profile with balancing actions due to volatile wind conditions. Throughout this period there ware unfavourable continental system conditions and an increased number of assets experiencing operational issues, reducing their overall capability, and meaning intervention from NESO was required to maintain secure system operation.

In comparison to February 2024 when the average monthly carbon intensity from NESO actions was 7.18g/CO2/kWh, February 2025 is 1.95g/CO2/kWh higher, however remains lower than the 2025 monthly average YTD.

RRE 1I Security of Supply

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds

The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.

There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

For context, the **Frequency Risk and Control Report** defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where 'f' represents frequency:

Deviation (Hz)	Duration	Likelihood
f > 50.5	Any	1-in-1100 years
49.2 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 48.8	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

February 2024-25 performance

Table: Frequency and voltage excursions (2024-25)

	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0	0	0	0	0	
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	1	0	0	0	0	
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0	0	0	0	

Supporting information

February performance

There were no reportable voltage or frequency excursion in February 2025.

[3] https://www.neso.energy/industry-information/industry-data-and-reports/system-performance-reports

RRE 1J CNI Outages

This Regularly Reported Evidence (RRE) shows the number and length of planned and unplanned outages to Critical National Infrastructure (CNI) IT systems.

The term 'outage' is defined as the total loss of a system, which means the entire operational system is unavailable to all internal and external users.

February 2024-25 performance

Table: 2024-25 Unplanned CNI System Outages (Number and length of each outage)

	2024-25											
Unplanned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0	0	0	0	
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	

Table: 2024-25 Planned CNI System Outages (Number and length of each outage)

	2024-25											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 265 mins	1 outage 203 mins	0	0	0	1 outage 205 mins	0	0	
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0	

Supporting information

February performance

There were no outages, either planned or unplanned, encountered during February 2025.

Notable events during February 2025

Migration of the Balancing Mechanism (BM) Registration process to the Single Markets Platform (SMP)

The BM registration process, for participation in the Balancing Mechanism (BM) has now moved to the Single Markets Platform (SMP). This process began on 14 February and has taken place over 2 SMP deployments and a data migration exercise. The key benefits that we can expect to see are as follows:-

- BM Registration data will now be visible to users through their access to SMP enabling self-service. This puts the data back in their hands whilst still ensuring that the BM Regulation team retains the gate keeper role ensuring compliance. This centralises all Unit registration within NESO into one place, SMP, as the single source of the truth.

- Aligning to our "digital first" ambition communication of data to downstream BM systems such as SORT and SPICE, and in the future Open Balancing Platform (OBP), will become automated where previously this has involved manual interventions

- The BM Registration process can be further enhanced over time in conjunction with feedback from our users. An initial focus area will be the integration of Single Market Platform Application Programming Interface (SMP APIs) process that will facilitate more opportunity for aggregated Balancing Mechanism Units (BMUs) made up of multiple assets. The potential to connect directly with Elexon through further automation also exists.

Battery Storage & Skip Rates Webinar

On 27 February, we held a Webinar to provide more information on our work to reduce skip rates. During this session we presented more details on our published data sets and the skip rate methodology, along with updates on our roadmap including key activities such as GC0166 and P462 delivery. This webinar formed part of our quarterly engagement with Industry, especially Battery Storage providers and was attended by over 100 participants, with a significant number contributing to the question and answer session.

Feedback from the session was positive with participants confirming that the session was useful and helped them understand better the new data that we are publishing on our portal.

Role 2

(Market developments and transactions)

Notable events during February 2025

Launch of the EBR Article 18 consultation for the new Quick Reserve Phase 2

On 12 February, we published the A18 consultation to industry for Phase 2 of Quick Reserve. Please see the documentation in the 'QR Phase 2 Consultation' folder for more details. The consultation closed on 12 March and we will now consider all feedback prior to its publication to Ofgem.

The primary focus of this Phase 2 Quick Reserve consultation is to enable participation of Quick Reserve to non-BM participants, with the auction estimated to go open for non-BM parties in late September 2025.

Demand Flexibility Service Webinar

The DFS released a recorded webinar on 14 February, providing an overview of its performance since receiving approval from Ofgem on 21 November 2024. The recording included key statistics, delivery volumes, performance metrics, savings, and a detailed breakdown of participation. The project team also announced plans to explore further development of the service to include a bi-directional offering. The recording has been viewed over 270 times in February.

On 20 February, we hosted a live Q&A webinar where we answered both pre-submitted and on-the-day questions from industry about the recorded material and the service in general. The session was well attended covering a diverse range of questions. The materials can be accessed through the links below.

LCM Commercial Policy update

Following the successful go-live of the LCM in December-2023, we have continued to improve the product and its value for consumers. As such, we have been seeking feedback from all our stakeholders to understand how the service is performing in practice and what improvements could be made. As a result of this we have decided to alter our approach to LCM procurement – we expect that this will increase the average accepted price although bids accepted for the service will depend on day to day market conditions. This will allow us to find an improved balance between locking in potentially cheaper options at a longer lead time, versus waiting until real-time, to minimize cost for the end consumer.

EMR Capacity Market Portal

As part of the continuous improvement phase for the new EMR Portal, the Delivery Body collaborate with a Customer User Group to prioritise customer experience enhancements. In February, we met with the group to confirm proposed scope items for portal improvements expected to be delivered in Q1 FY26 and presented demonstrations for customer priority enhancements being implemented prior to the end of the Q4 FY25. These changes were well received by the User Group. Supporting information can be accessed on our NESO website via the following link Capacity Market Portal | National Energy System Operator.

Role 3

(System insight, planning and network development)

Notable events during February 2025

Connections: Progression Commitment Fee proposed

In February 2025, we submitted an updated proposal to the Connections & Use of Codes (CUSC) governance panel, to introduce a proportionate Progression Commitment Fee for connections customers. This fee is part of the package of measures to ensure that there are effective mechanisms in place to make Connections Reform a success.

Our proposal was informed by feedback from industry, including through a call for input in late 2024. The proposed fee would be included in future connection contracts if material capacities of projects exit the reformed connections queue. The fee would provide an additional incentive for projects in the connections queue to continue to progress and deliver progress towards Clean Power targets and beyond.

For further detail please see New tool to drive connections queue progress proposed.

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