23 December 2025

Monthly Incentives November 2025 Report

Business Plan 3 (2025-26)

Contents

Introduction

As part of the RIIO-2 price control, we published our third Business Plan (BP3) in January 2025. It sets out our delivery focus for the period April 2025 to March 2026 against eight Performance Objectives. Each Performance Objective is underpinned by a set of Success Measures intended to represent the key deliverables or milestones which, if achieved, demonstrate progress towards the Performance Objective.

Our BP3 Performance Objectives for 2025/26

WHOLE ENERGY

Strategic Whole Energy Plans

NESO will establish the capabilities, foundations and methodologies needed to deliver national and regional strategic whole energy plans.

Enhanced Sector Digitalisation and Data Sharing

NESO will work with the sector to develop an aligned and interoperable digital ecosystem that enables industry digitalisation collaboration utilising innovation, underpinned by transparent data sharing and access.

Fit-for-Purpose Markets

NESO will support the government in making informed decisions on policy and market reform across the whole system. We will also continue to reform our own markets to level the playing field and deliver value to consumers.

Secure and Resilient Energy Systems

NESO will improve whole energy system emergency preparedness and resilience. We will ensure the necessary capabilities and requirements are in place and facilitate industry readiness to meet the Electricity System Restoration Standard.

Separated NESO Systems, Processes and Services

NESO will transition remaining systems, processes and services from National Grid to NESO ownership to enhance our capabilities and establish our autonomy and full independence.

Clean Power 2030 Implementation

NESO will play a pivotal role in securing clean power for Great Britain by 2030 on the path to net zero by 2050. Building on our 2024 advice to government on pathways to a clean, secure, operable and deliverable electricity system, we will move to action and implementation in line with the government's CP30 action plan.

ELECTRICITY

Operating the Electricity System

NESO will transparently operate a safe, reliable and efficient system throughout BP3, while continuing to transform the capabilities of our people, processes and systems to enable secure zero-carbon operation of the system by the end of 2025.

Connections Reform

NESO will drive delivery and implementation of a reformed connections process that enables projects needed for 2030 and beyond to connect in a timely and coordinated manner.

The NESO Performance Arrangements Governance Document (NESO PAGD) for BP3 was published by Ofgem in February 2025. This document sets out the process and criteria for assessing the performance of NESO, and the overarching reporting requirements which form part of the incentives scheme for the BP3 period. Further detailed reporting requirements are also set out in Ofgem's Determinations.

Every month, we report on a set of Reported Metrics. In Business Plan 2 (BP2), these quantitative measures were referred to as Performance Measures (including Performance Metrics and Regularly Reported Evidence). However, for BP3 these have been re-termed to Reported Metrics to reflect the change in the evaluation methodology and adoption of Success Measures. All BP2 measures have been retained for BP3 except for the following as set out in Ofgem's Determinations:

- RRE 1E - Transparency of operational decision making (replaced with new skip rate measure)
- Metric 2Ai – Phase-out of non-competitive balancing services (covered by Success Measure under Fit-for-purpose markets)
- RRE 3X - Timeliness of connection offers
- RRE 3Y - Percentage of 'right first time' connection offers

In several cases our performance against Reported Metrics directly contributes to our Success Measures. In other cases, they apply reputational incentives which are supplementary to Ofgem's public performance assessment. Ofgem will no longer measure our performance against pre-determined benchmarks for the Reported Metrics, however we may still include them as part of our supporting evidence in our reports.

Every quarter, we will provide progress updates for each of the Performance Objectives set out in our BP3 plan. This will include evidence in relation to the Success Measures and where relevant in relation to Ofgem's expectations in their Determinations.

At six months and end of year, we will also publish the results from our Stakeholder Satisfaction Survey and provide an update on how we are delivering Value for Money.

See below a summary of the reporting requirements for our published incentives reports throughout BP3:

Report	Published report content	Dates required by
Monthly	• Reported Metrics	17th working day of the following month
Quarterly	• Reported Metrics • Performance Objectives Progress updates	17th working day of the following month
Six-month and end of year	• Reported Metrics • Performance Objectives Progress updates • Value for Money reporting • Stakeholder survey results	23 October 2025 and 16 May 2026

Following our BP2 submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The purpose of the CMF is to monitor the delivery and value for money of our IT investments and our exit from the Transitional Services Agreement with National Grid plc.

As per the BP3 NESO PAGD, we are required to continue providing quarterly reports directly to Ofgem as part of the CMF throughout BP3. We feel it is also important to share updates with our external stakeholders and industry as part of the framework. Therefore we will include a summary of the CMF update every six months alongside our incentives reporting.

For BP3 we will no longer include a "Notable Events" section in our incentives report – you can stay up to date with our latest news and events on the NESO website or by subscribing to our weekly newsletter.

Please see our incentives website for more information on the scheme and to access our reports.

Reported Metrics

Summary of Reported Metrics

The table below summarises our Reported Metrics for November 2025:

	Reported Metric	Performance
1	**Balancing Costs**	**£265m**
2	**Demand Forecasting**	Forecasting error of **641MW**
3	**Wind Generation Forecasting**	Forecasting error of **5.05%**
4	**Skip Rates**	Post System Action (PSA) Offers: **33%** Bids: **35%** Combined: **34%**
5	**Carbon intensity of NESO actions**	**6.68 gCO_2/kWh** of actions taken by NESO
6	**Security of Supply**	**0** instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. **0** voltage excursion.
7	**CNI Outages**	**1** planned, **0** unplanned system outages.

1. Balancing Costs

Performance Objective

Operating the Electricity System

Success Measure

We will further develop and implement initiatives from our Balancing Cost Strategy to demonstrate cost efficiency through the Balancing Cost metric (BP2: Metric 1A). In consultation with industry, we will publish an updated Balancing Cost Strategy by June 2025.

This Reported Metric measures NESO's outturn balancing costs (including Electricity System Restoration costs).

For consistency with previous RIIO-2 incentives reporting, we have included a view of a benchmark based on the BP2 methodology. Note that as per the PAGD, Ofgem will not assess our performance against this metric as below/meets/exceeds, therefore the thresholds have been removed.

When setting up the BP2 benchmark methodology, analysis showed that the two most significant measurable external drivers of monthly balancing costs are wholesale price and outturn wind generation. The BP2 methodology uses the historical relationships between those two drivers and balancing costs:

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

The formulas used for the 2025-26 benchmark 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.

November 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

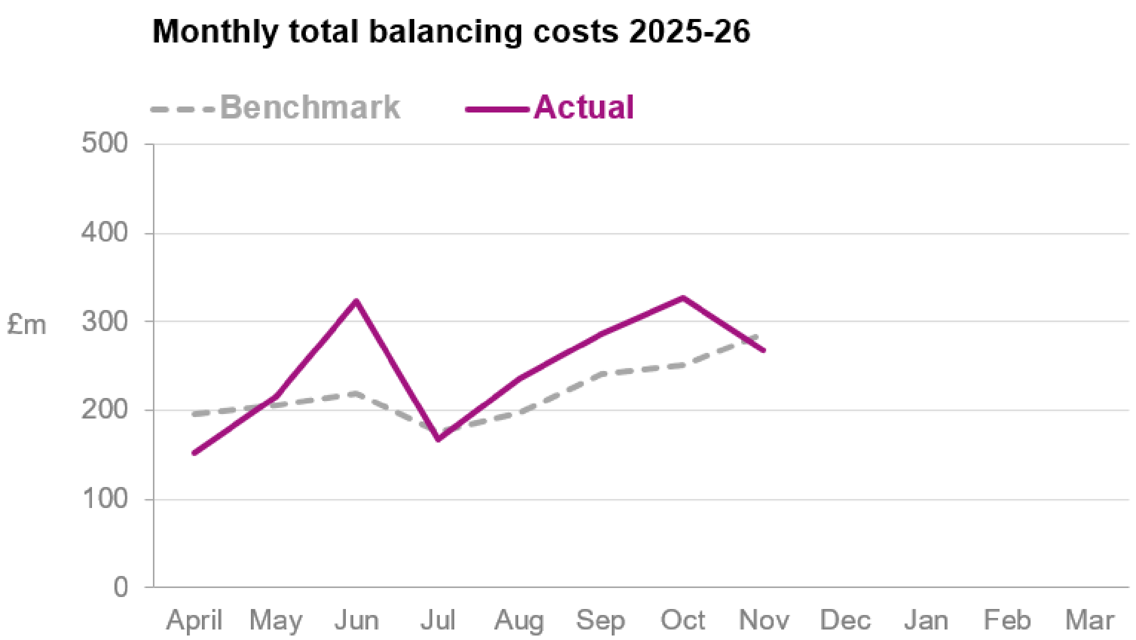


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	4.1	4.7	5.4	3.3	4.4	6.4	6.6	7.9					42.8
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72	77	82					n/a
Benchmark*	195	206	219	176	197	241	251	286					1772
Outturn balancing costs[1]	**152**	**215**	**324**	**167**	**236**	**287**	**326**	**265**					**1975**

[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.

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.

*Ofgem no longer use a benchmark to assess our performance against this Metric however, we continue to report this as an indicator against the outturn figure.

Supporting information

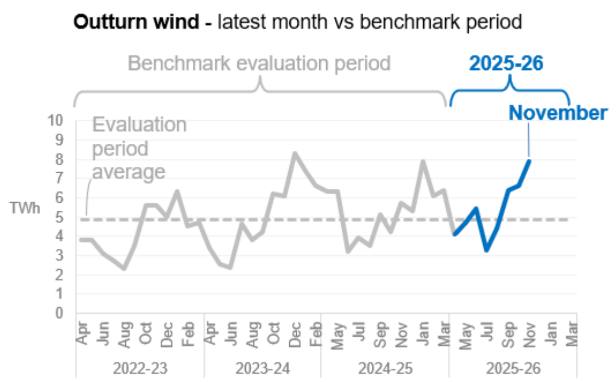
BALANCING COSTS METRIC & PERFORMANCE

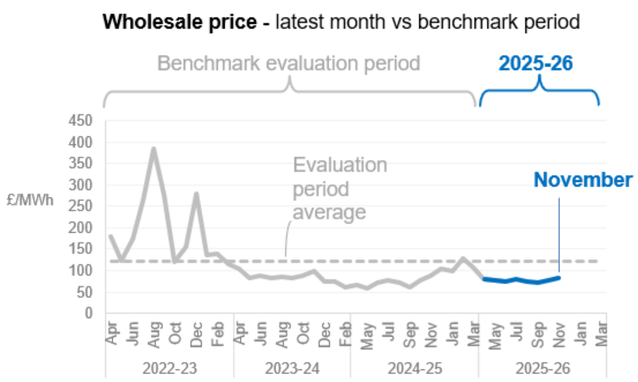
This month's benchmark

The November's benchmark of £286m is £35m higher than October 2025 and reflects:

- An outturn wind figure of 7.9 TWh that is higher than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 5.0 TWh) and is higher than October 2025's figure (6.6 TWh).
- An average monthly wholesale price (Day Ahead Baseload) has increased compared to October 2025 but is lower than the same period last year. It falls below the evaluation period average.

The higher wind outturn and wholesale prices has caused the increase in November's benchmark compared to October.





Variable	November 2025	October 2025	November 2024
Average Wholesale Price (£/MWh)	**82**	**-5**	**-21**
Total Wind Outturn (TWh)	**7.9**	**-1.3**	**-2.6**
Benchmark (£m)	**286**	**-35**	**-62**

*The rows show the outturn measures for this month and difference in the previous month and same month last year.

Balancing Costs - Overview

The total balancing cost for November was £265.5m, which is £21m (~7%) below the benchmark.

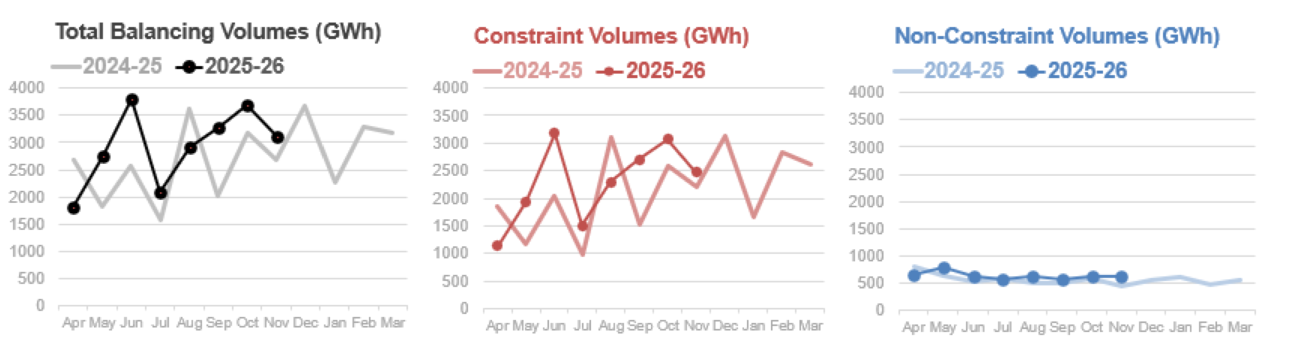
November saw a significant increase in wind outturn to 7.9TWh compared to October at 6.6TWh. This rise in outturn was mostly driven by the increase in outturn in England and Wales, this is due to higher wind speeds throughout most of the month with storm Claudia also being a factor. Along with increased wind speeds there was also an increase in demand compared to October which allowed for more wind generation to be utilised rather than curtailed, which reduced the impact of high wind on overall costs.

Voltage constraint costs have seen an increase this month due to some units that would have provided reactive support being on outage. This follows with the drop in stability constraint costs as the two are co-optimised.

Non constraint costs have decreased by £20.5m which is proportionate to the decrease in volume of actions which also shows that BM prices remained closely in line with October.

Average wholesale prices increased by £5/MWh from October 2025 likely because of increased domestic demand this month. The volume weighted average (VWA) price of bids was -£5.4/MWh, which is less than October's price which was -£20.42/MWh. This negative bid price reflects that most of the bid actions taken were to curtail wind, however it is much lower than October indicating the lower proportion of bids on wind due to the higher demand allowing more wind to be used. The VWA price for offers increased to £132.4/MWh, compared to £125.4/MWh in October, aligning with the rise in wholesale prices.

Absolute Balancing VOLUMES (GWh) monthly vs previous year

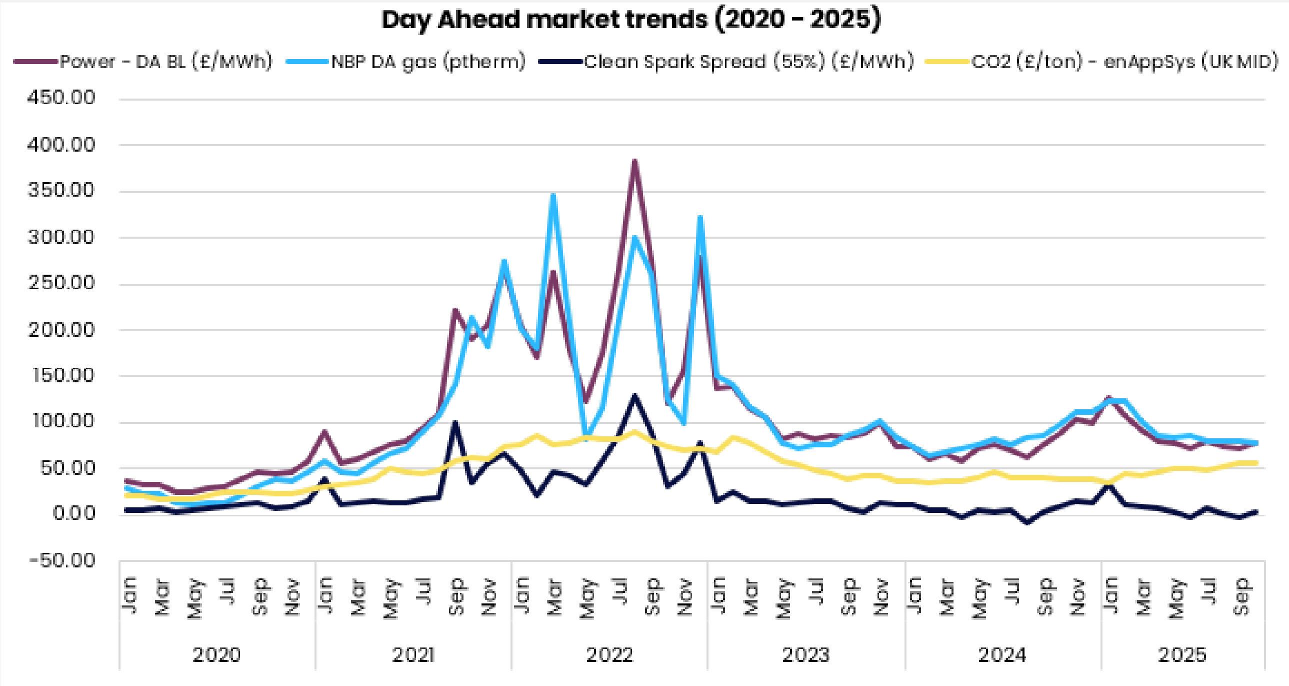


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

In November, gas prices dropped marginally to 75.94p/Therm, however power prices saw an increase to £81.96/MWh along with CO2 also rising to £57.33/ton. The month was shaped by seasonal temperature shifts as we continue to move further into winter and the presence of storm Claudia causing disruption mid-month. We have seen domestic demand increase compared to October, as temperatures have continued to drop however this does closely align with previous year's demand. To meet this demand we have seen a very even increase across all fuel types with the overall split being very similar to October.



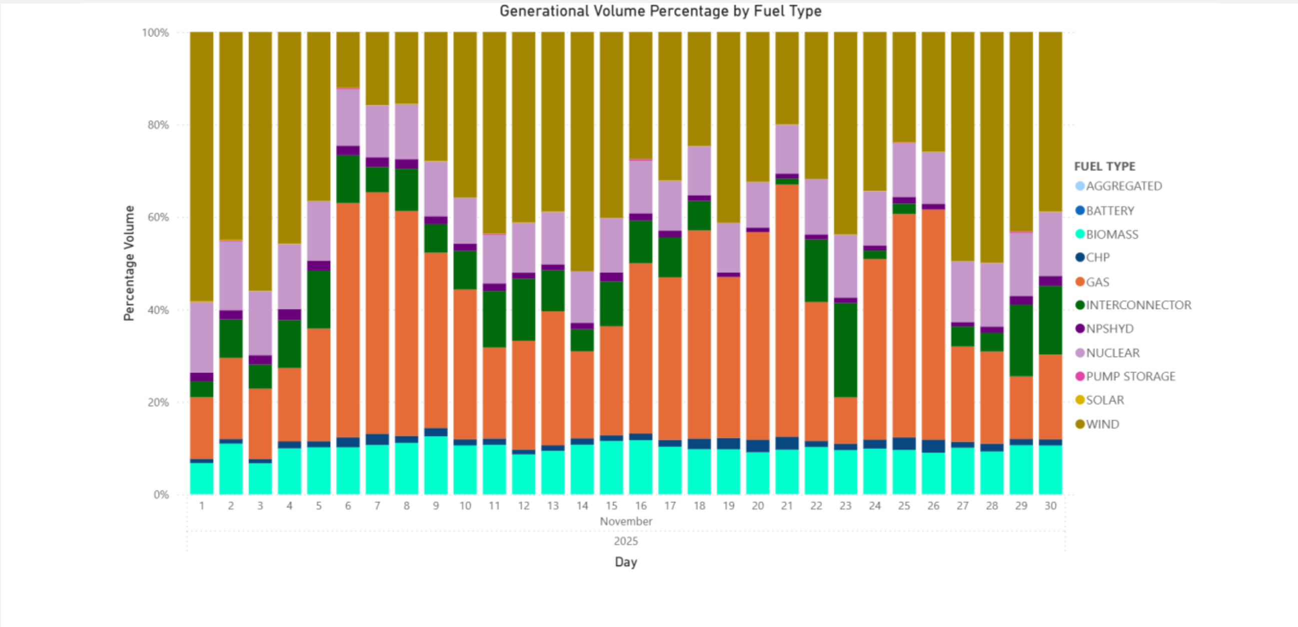
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

In November, wind was the largest contributor to electricity generation, making up 36% of the total mix. This was followed by CCGTs at 32% and Nuclear at 12%. The pattern is consistent with October, where Wind, CCGTs and Nuclear also held the top three positions in the generation mix.

The chart shows that wind generation was particularly strong throughout the whole month, with only 6 days where wind generation is less than 25% of the total daily generation being the 7, 8, 9, 18, 21 and 25.

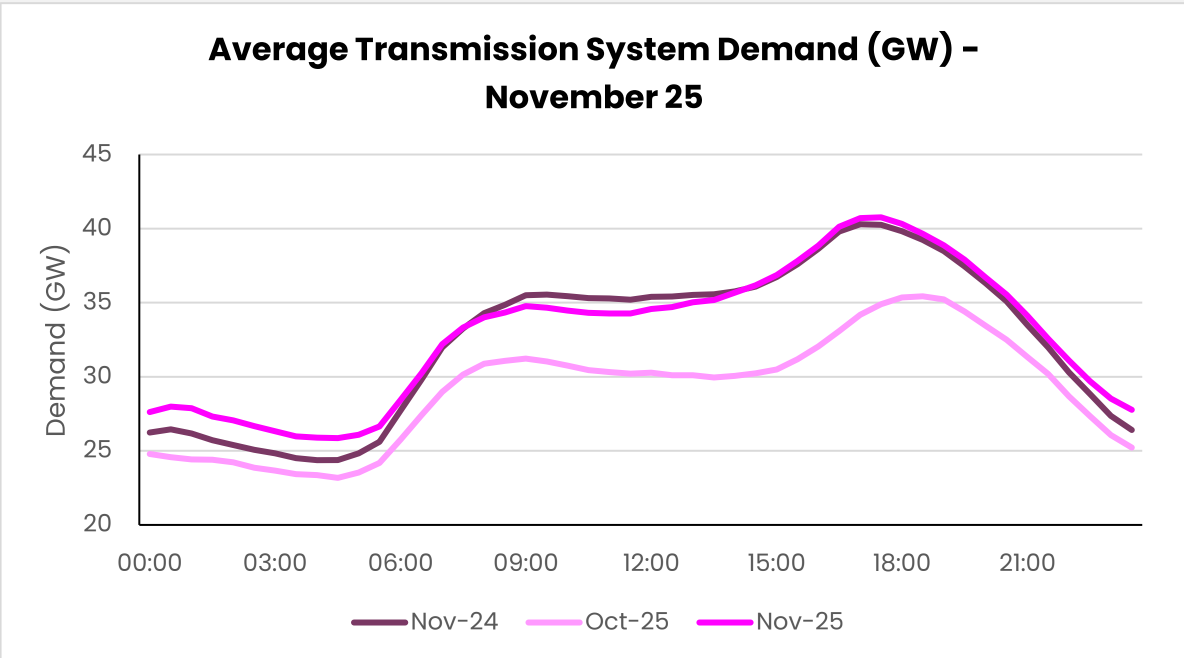
In contrast, we had 3 days where wind generation was above 50% of the total generation being on the 1, 3 and 14. Noting as well that we saw the highest wind generation recorded in a settlement period on the 11 November at 7:30pm with 22,711 MW however, this has since been broken again in December. But this does not coincide with the day of highest outturn, however we did see very minimal wind curtailment on this day.



*Generation mix includes exports from interconnectors.

Transmission System Demand

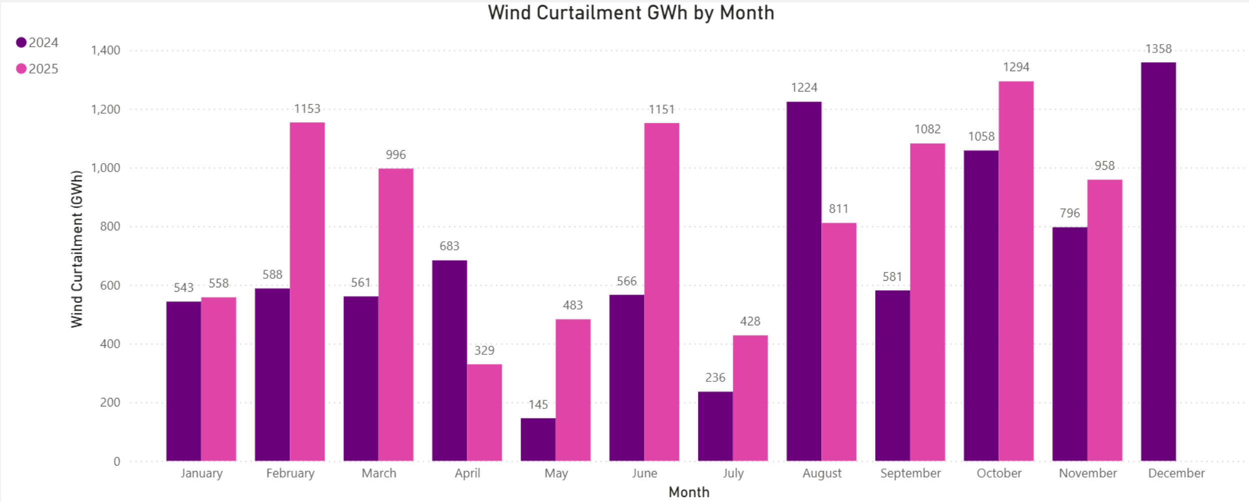
In November the average Transmission System Demand (TSD) was higher than October throughout the whole day, which can be expected due to increased hours of darkness, colder weather, and lower levels of embedded solar generation during the daytime. Comparing November 2025 to November 2024, the average TSD was similar throughout the day with higher average overnight demand between the hours of 6pm and 6am. This similarity in average demand is likely linked to the comparable levels of solar hours between the two years. Economic and market drivers likely also played their part, with lower year-on-year wholesale power prices reducing incentives for demand-side curtailment.



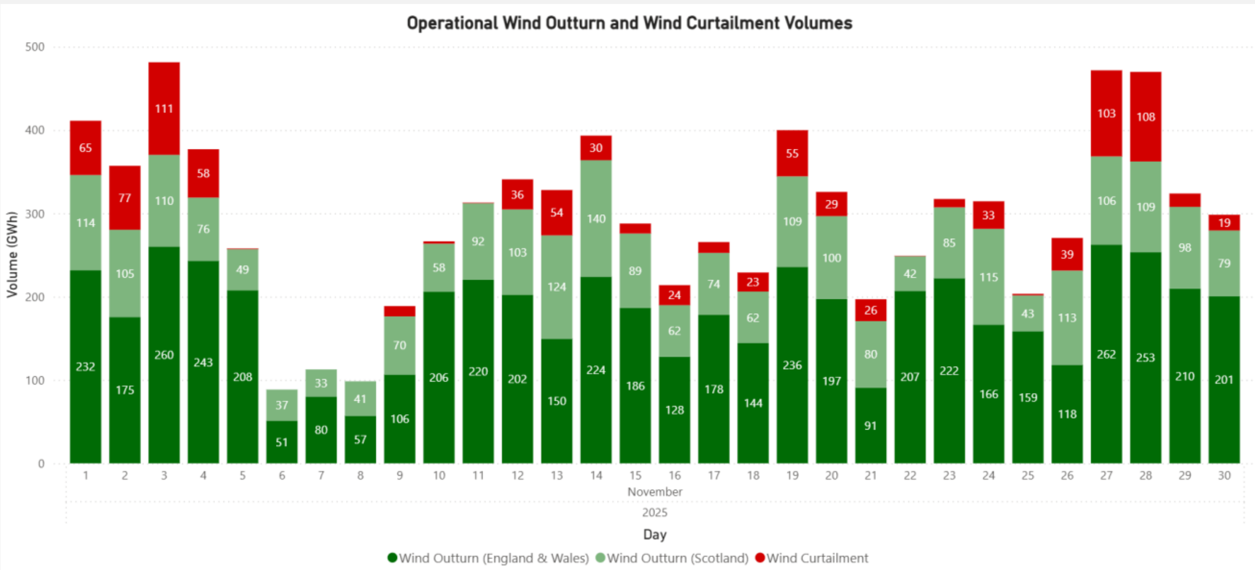
Wind Outturn

Mid November wind outturn was influenced by storm Claudia with significant rainfall and wind speeds across England and Wales driving up wind generation.

Overall wind outturn rose from 6.6 TWh in October to 7.9 TWh in November, with a 26% increase in England & Wales (from 4.2 TWh to 5.4TWh) and a 5% increase in Scotland (from 2.4 TWh to 2.5 TWh) compared to the previous month, giving a 20% increase overall. There was a 26% decrease in the volume of wind curtailment, which given the increase in overall wind outturn since last month this can namely be associated with the increase seen in demand allowing for less wind to be curtailed to manage thermal constraints. With variable weather conditions throughout the month, the highest volume wind curtailment days were spread throughout the month; on 3 November (111GWh), 27 November (103GWh), and 28 November (107GWh). With most days seeing considerably less and just 0.4 GWh curtailed on the day we saw the highest wind output in a single settlement period.



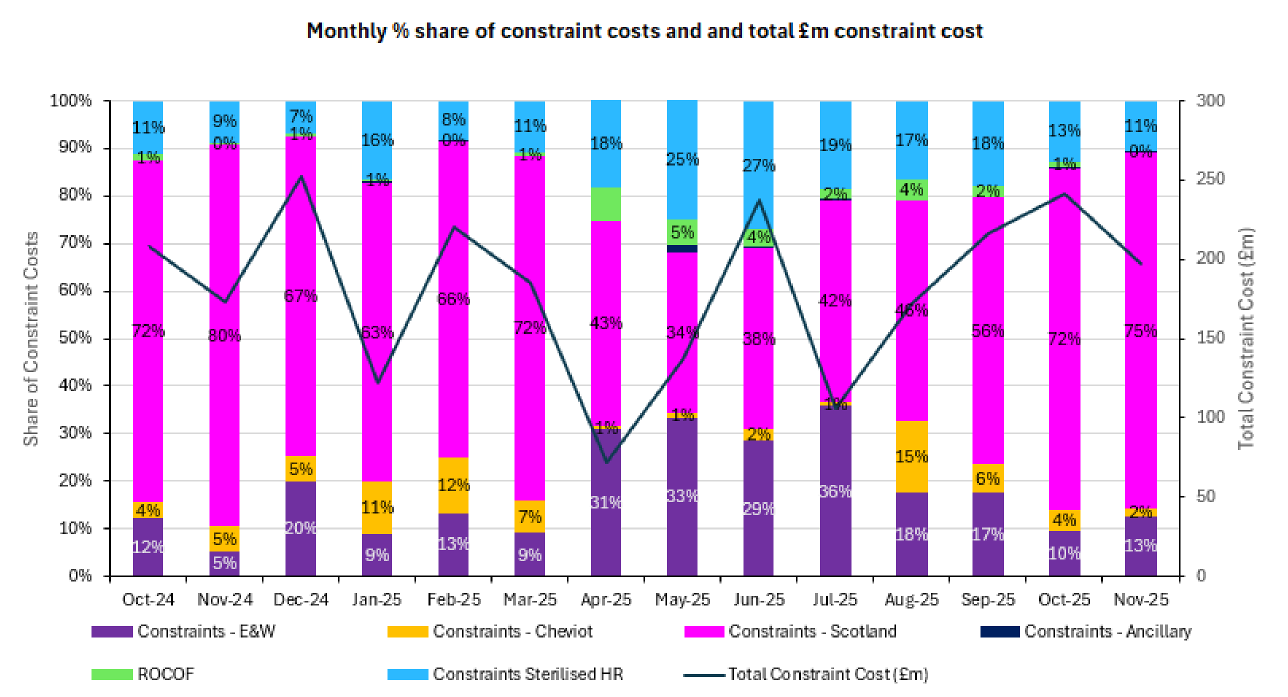
The day with the highest volume of wind curtailment occurred on Monday 3 November with 111 GWh. There was a total wind outturn of 370 GWh on this date, the highest outturn this month. This was also the overall highest-costing day in November.



Constraints

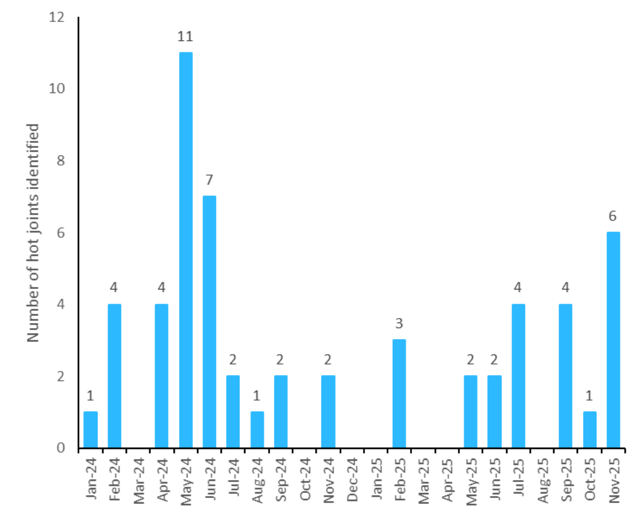
Constraint costs decreased from £240.9m in October to £196.7m in November, a decrease of £44.6m. England and Wales saw a small increase in constraint costs with a £2m increase however all other areas saw a decrease with the most influential area for this reduction being Scotland with a £26.2m reduction.

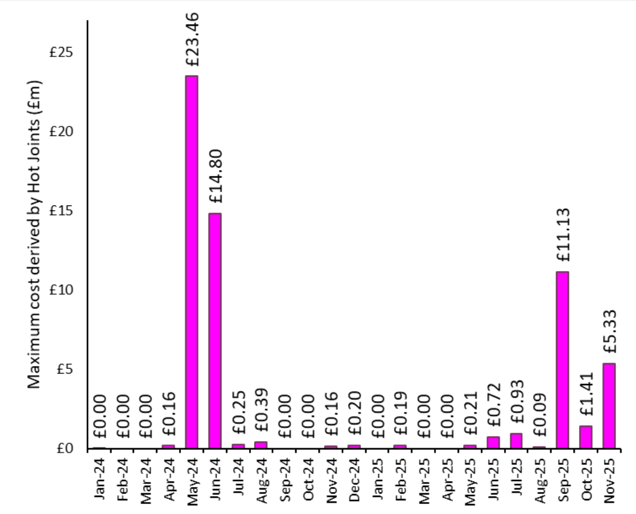
Wind levels across England & Wales and Scotland increased in November however, we also saw an increase in demand needing to be met along with the location we saw the more extreme wind conditions being in areas with less constraints. These conditions combined mean we had more useable wind generation and curtailed less volume compared to October.



Network Availability

Hot joints refer to transmission equipment that tends to overheat during normal operational conditions. Transmission Owners are responsible for notifying NESO of any service reductions associated with this equipment. Hot joints in the system have both operational and economic impacts. In November, six hot joints were identified: three concentrated in the North-West of England (Penwortham), two to the north of London (Sundon), and one in the North-East of England (Osbaldwick). The estimated maximum cost to the system for these hot joints was approximately £5.3 million in November.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): November 2025 vs October 2025

		(a) Oct-25	(b) Nov-25	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Non-Constraint Costs	Energy Imbalance	0.7	-4.6	(5.3)	
	Operating Reserve	13.5	5.9	(7.6)	
	STOR	8.3	4.4	(3.9)	
	Negative Reserve	1.6	1.7	0.1	
	Fast Reserve	15.5	15.2	(0.3)	
	Response	23.5	23.0	(0.6)	
	Other Reserve	1.3	1.6	0.4	
	Reactive	13.2	11.9	(1.3)	
	Restoration	6.1	3.4	(2.6)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	1.6	6.2	4.6	
Constraint Costs	Constraints - E&W	22.9	25.0	2.1	
	Constraints - Cheviot	10.7	3.2	(7.6)	
	Constraints - Scotland	173.4	147.2	(26.2)	
	Constraints - Ancillary	0.2	0.4	0.2	
	ROCOF	3.0	0.3	(2.7)	
	Constraints Sterilised HR	30.7	20.7	(10.0)	
Totals	Non-Constraint Costs - TOTAL	85.3	68.7	(16.5)	
	Constraint Costs - TOTAL	240.9	196.7	(44.2)	
	Total Balancing Costs	**326.2**	**265.5**	**(60.7)**	

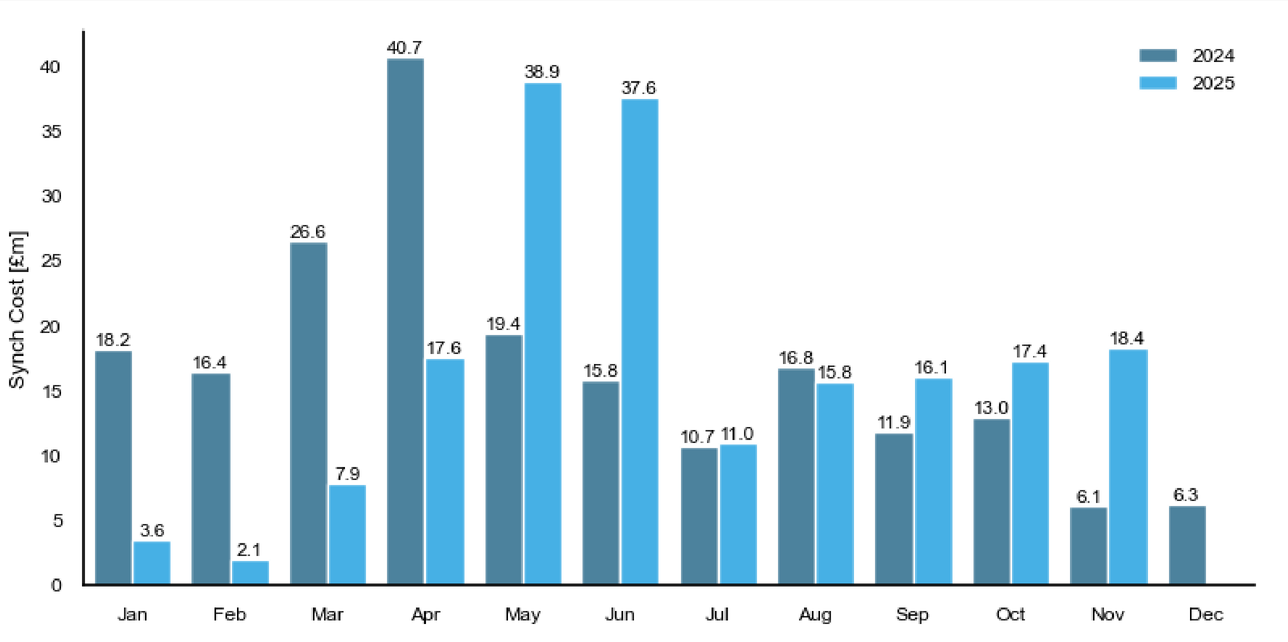
As shown in the totals from the table above, constraint costs decreased by £44.2m and non-constraint costs decreased by £16.5m which results in an overall decrease in costs of £60.7m compared to October 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£33.8m **Constraint – England & Wales: +£2.1m** **Constraint Sterilised Headroom: -£10m** Overall constraint costs decreased by £44.2m, which coincided with a decrease in the absolute volume of actions taken. This was partly due to an increase in demand along with a lower number of outages taken in November reducing the spend on thermal constraints. **ROCOF: -£2.7m** The drop in costs this month represents a higher system demand compared to the previous month, which leads to more synchronous generators being self-dispatched to meet load, meaning these generators do not need to be dispatched through the BM to provide frequency services.	**Constraints – Scotland & Cheviot: +£7.9m** **Constraints – England & Wales: +£15.7m** **Constraints Sterilised Headroom: +£5.5m** Constraint costs across GB have increased by £23.1m compared to November 2024, largely driven by a rise in wind output(50%) and the resulting curtailment (20%) and balancing actions taken to manage this. Of note is the increase in England and Wales constraints, which links to the higher wind speeds seen in this region along with the higher impact from storm Claudia. **ROCOF: -£0.5m** Both November 2024 and 2025 spending was low, however there was a slight decrease in inertia spend compared to November 2024. This is due to a lower volume of actions taken comparatively.

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. In November, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £18.4m. This represents an increase of approximately £1m compared to October 2025 and is £12.3m higher than the same period last year (November 2024).

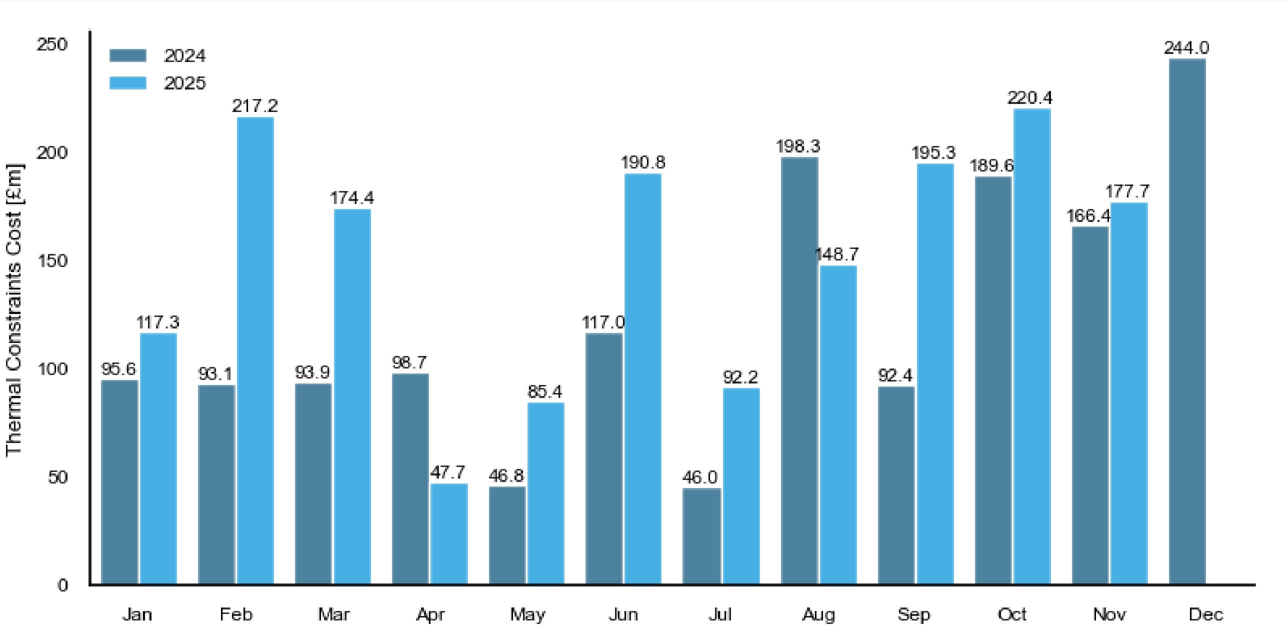


Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism.

Most voltage costs arise from the South-West region of Great Britain, where the system relies on Combined Cycle Gas Turbines (CCGTs) for voltage management. However, the system operational condition and outages in other areas also influence the system spending. An interconnector in the south, along with its Static Synchronous Compensator (STATCOM), will be in outage until the start of December, which may increase the voltage machine requirements in the South-West.

Thermal – Monthly system cost of actions for thermal management across 2024 and 2025:

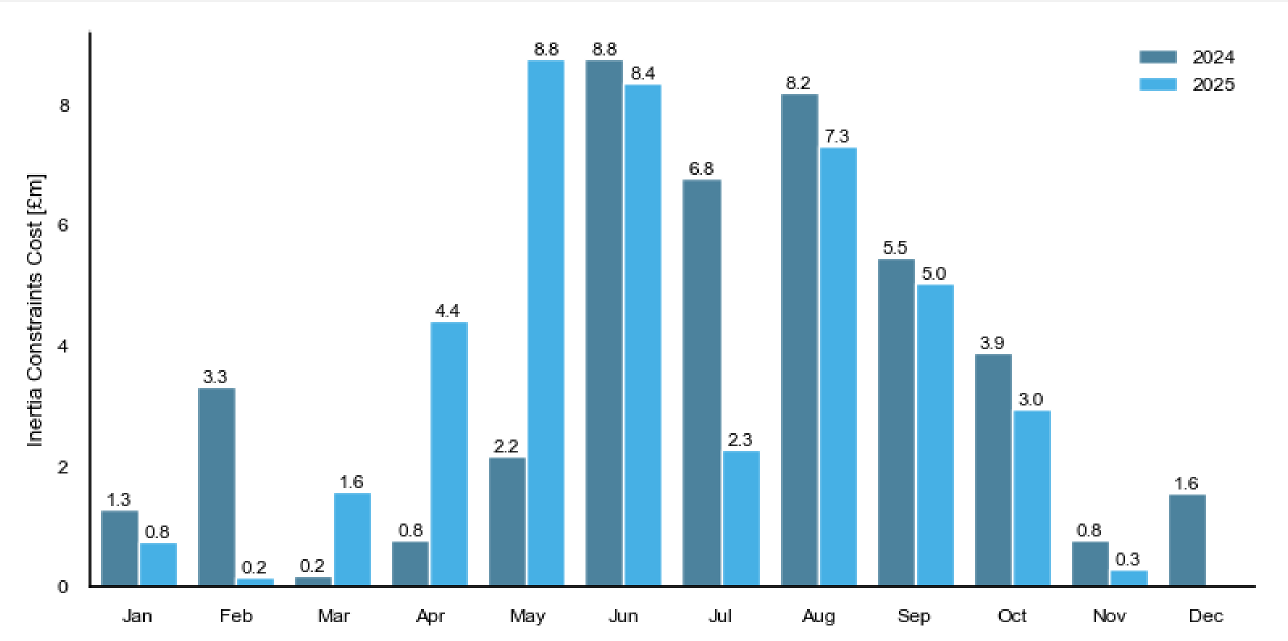
Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints is highly correlated with levels of curtailment in Scotland, as well as planned or forced outages in transmission assets that limit the grid's transfer capacity. Thermal constraints constitute the vast majority of the system constraints, accounting for a significant percentage of system actions. In November, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £177.7m, reflecting a decrease in costs of over £42.7m compared to the previous month (£220.4.3m). When compared to the same period last year (£166.4m in November 2024), the cost rose by £11.3m.



November 2025 saw a reduction in wind curtailment which was in proportion to the drop in thermal constraint costs. Wind curtailment reduced from 1,295 GWh in October to 960GWh in November which is a 26% decrease, coinciding closely with the 20% decrease on thermal constraint costs

Inertia – Monthly system cost of actions for inertia management across 2024 and 2025:

Inertia refers to the resistance of the system to changes in its rotational speed. Inertia is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs, but also includes hydro, pumped storage, biomass, and Combined Heat and Power (CHPs), among others. The costs associated with inertia tend to be marginal in the system compared to thermal or voltage constraints. In November, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £0.3m, resulting in a decrease of £2.7m compared to last month (£3m) and £0.5m lower than November 2024.



The inertia expenditure fell in November despite higher wind generation, which made up around 36% of the total generation mix. The drop in inertia cost is likely linked to the higher spend on Voltage as units instructed for voltage also provide inertia, given voltage is the initial requirement the actions are flagged for, they are not flagged for inertia. The increased presence of synchronous units naturally boosted system inertia, reducing the requirement for NESO to procure additional inertia services through the Balancing Mechanism.

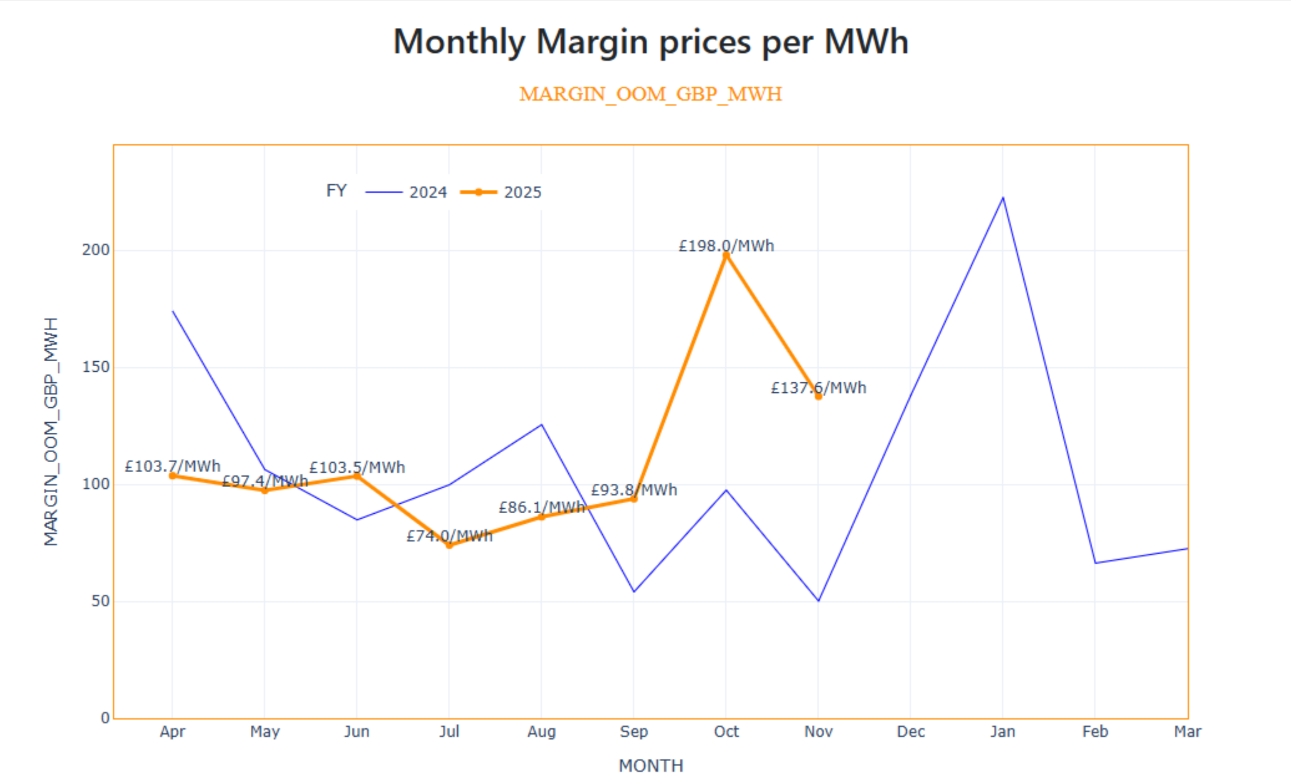
Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£1.3m Reactive costs have dropped on last month reflecting a reduction in the volume of actions taken.	**+£1.2m** Reactive costs have risen on last year reflecting an increase in volumes of reactive power required to maintain voltage.

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 decreased to £137.6/MWh in November from £198/MWh in October 2025. This is around the same proportion of decrease, but still higher prices compared to the previous year which saw a decrease from £97.5/MWh down to £50.1/MWh in November 2024.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£7.6m **Fast Reserve: -£0.3m** There was a 135 GWh decrease in volume of operating reserve to secure the system compared to October.	**Operating Reserve: +£2.2m** **Fast Reserve: -£0.9m** There was a 103 GWh increase in the volume of operating reserve required to secure the system compared to November 2024 which is proportionate to the increase in spend we have.

We are currently in the process of quantifying the benefits associated with Balancing Reserve, and the results will be shared in the coming months.

Response Costs/Volumes

Our Dynamic Services for response, Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR) continue to benefit from 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
-£0.6m There was a 12 GWh decrease in the absolute volume of actions compared to October. Also, clearing prices for DC, DM, DR services were all lower this month than last.	**+£11 m** The volume of actions taken for response increase by 6 GWh compared to November 2024 and clearing prices were higher, most notably for DR.

Dynamic Services Average Clearing Prices (£/MW): November 2025 vs October 2025

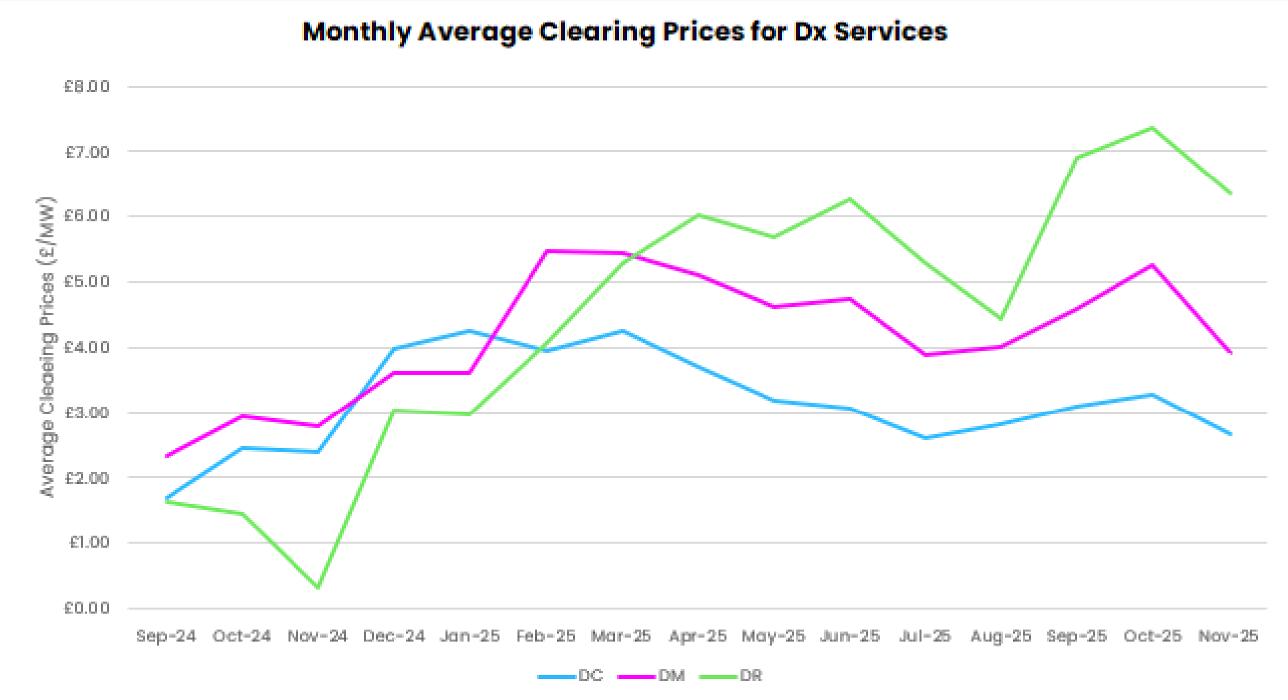
		(a) Nov-25	(b) Oct-25	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Dynamic Services	DC	2.7	3.3	(0.6)	
	DM	3.9	5.2	(1.3)	
	DR	6.3	7.4	(1.0)	

Dynamic Services Average Clearing Prices (£/MW): November 2025 vs November 2024

		(a) Nov-25	(b) Nov-24	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Dynamic Services	DC	2.7	2.4	0.3	
	DM	3.9	2.8	1.2	
	DR	6.3	0.3	6.0	

Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR) decreased in November, breaking the upward trend observed in recently. This increase is largely driven by reduced procurement levels, which were influenced by higher demand on the system last month.

Compared to November last year, all three dynamic services have seen a rise in average clearing prices, reinforcing the trend seen recently for higher year on year prices.

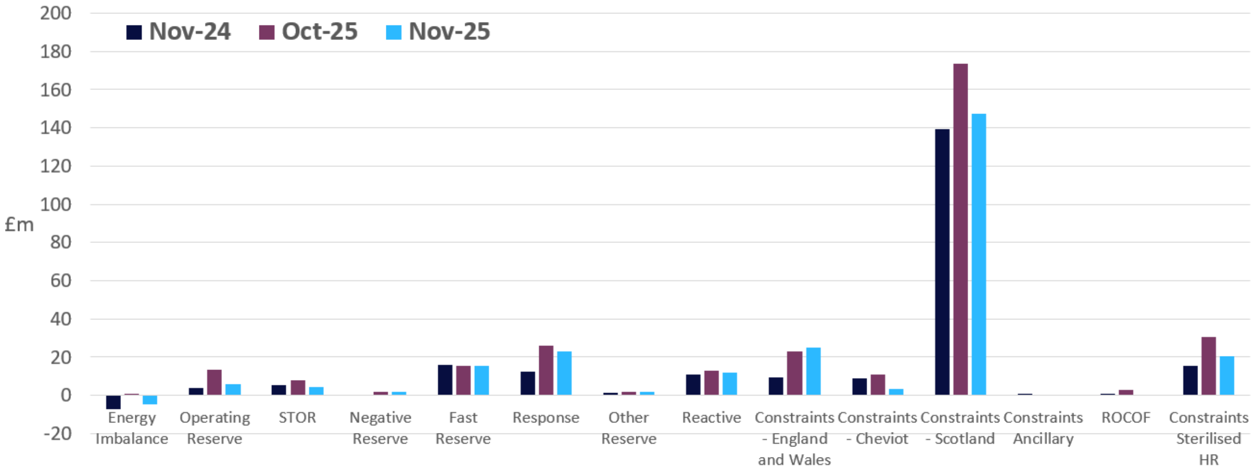


Comparison breakdown

Constraint costs decreased by £44.2m compared to the previous month. Higher costs were seen in England & Wales, though there was a decrease in Scotland and Cheviot constraint costs which is likely reflective of the higher wind generation seen in England and Wales due to higher wind speeds in this region. The lower costs are in line with an overall lower volume of wind curtailment November compared to October and, linked to the higher demand levels seen. Voltage spending increased, reflecting a combination of reactive equipment and an interconnector on outage, whilst inertia spending decreased month-on-month, reflecting the increase in actions on voltage which have the side-effect of bringing more inertia onto the system.

Thermal constraints are currently the largest component of balancing costs. We are progressing several initiatives to reduce thermal constraint volumes/costs including the Constraints Collaboration Project and Constraint Management Intertrip Service. Network Service Procurement projects for voltage and stability are also helping to provide solutions for network management at lower costs.

October Cost Breakdown (£m)
Last year (2024-25) | Last month (2024-25) | This year (2025-26)



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £75.8m in November 2025. This is an increase of roughly £42.3m relative to October 2025 (£33.5m). The most valuable action was the enhancement of Lambhill – Windyhill 275 kV capacity due to winter ratings, which resulted in an important improvement of a Scottish constraint by roughly 100 MW. The cost saving for this action is estimated in £21.78m.

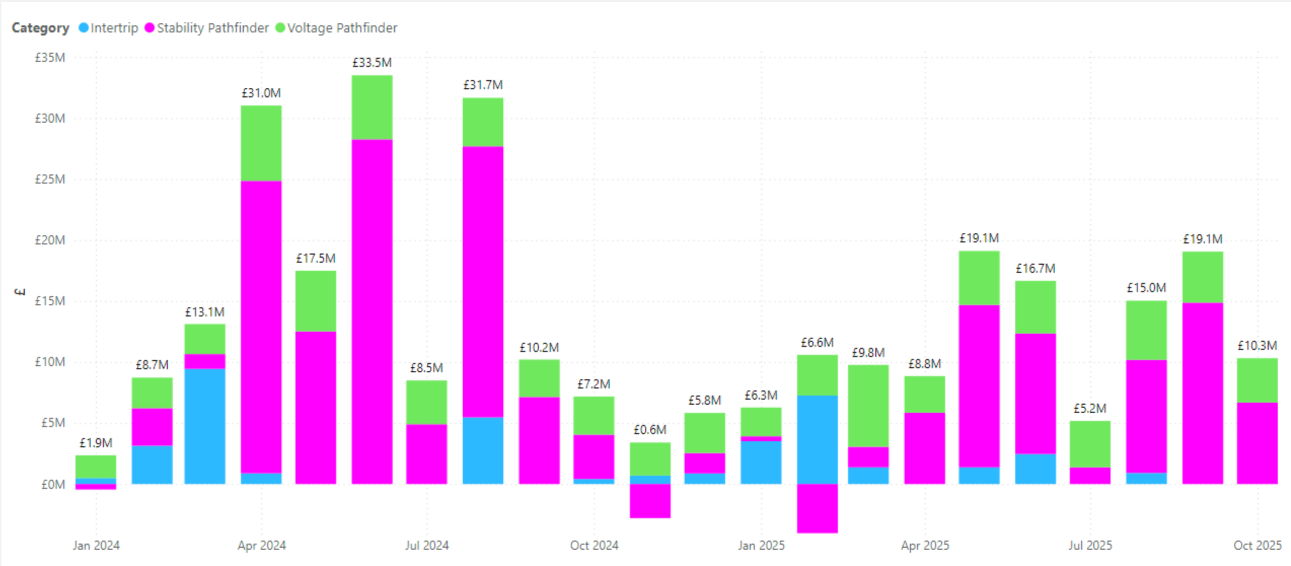
Cost Savings – Trading

The Trading team were able to make a total saving of £34.0m in November through trading actions as opposed to alternative BM actions, representing a 42% increase on the previous month. Similarly to October, trading savings were mainly driven by margin trades on the interconnectors, particularly due to large volumes of buy trades on the 20th and 21st where NESO saw market prices in excess of £3000/MWh. There was an increase in savings from constraint trading compared to October, along with a slight increase in trading savings for voltage management due to high wind outturn. The day with the greatest trading savings was on 21 November at a cost of £21.6m with savings being made on margin. The day with the greatest spend on trades was the 21 November at a cost of £15.6m with the greatest component being for margin.

Cost Savings – Network Services (NS)

We are using Network Services (NS) 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, Voltage Pennines, and Stability Phase 1 have delivered approximately £94.1 m in savings across 2025/26 to date (April – October 2025). Figures for Stability Pathfinder in September have been amended due to data inaccuracy.

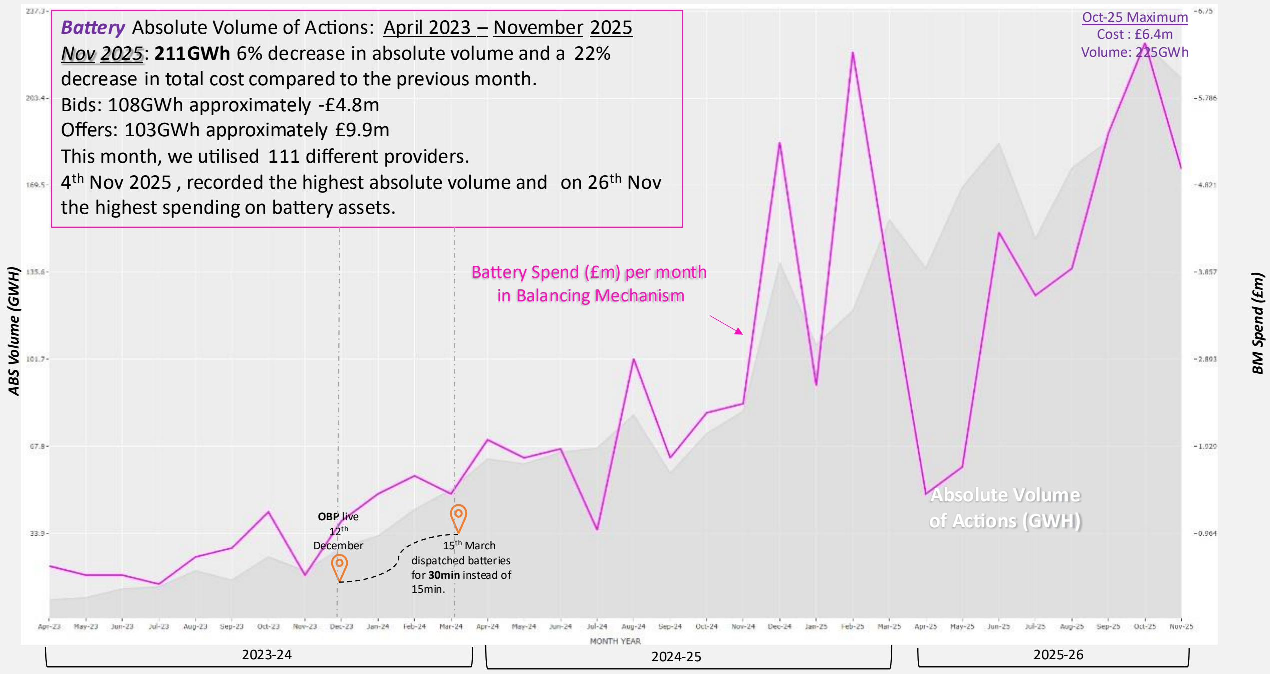
Monthly Savings from Network Services (NS)



NOTABLE EVENTS

Monthly Absolute Volume of actions and spend for Batteries in the BM

November 2025



This graph illustrates a clear upward trend in both cost and volume over the observed period from April 2023 through November 2025. Early on, both metrics remain relatively low and stable with minor fluctuations until late 2023 when the first stage of the Open Balancing Platform (OBP), our new platform to support bulk dispatch, went live on 12 December 2023. There is an initial spike followed by continued growth throughout 2024 with periodic dips and peaks—most notably sharp increases around August-September of each year. 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.

In comparison to the previous month, November 2025 experienced a decrease from the whole period maximum, in both the overall volume of battery actions and total costs. Since April 2025, the absolute volume of battery dispatch has nearly tripled compared to the same period last year and has increased more than fifteenfold since April 2023. This growth underscores our dedication to enhancing the flexibility of energy provision through battery storage and small Balancing Mechanism Units (BMUs).

DAILY CASE STUDIES

Daily Costs Trends

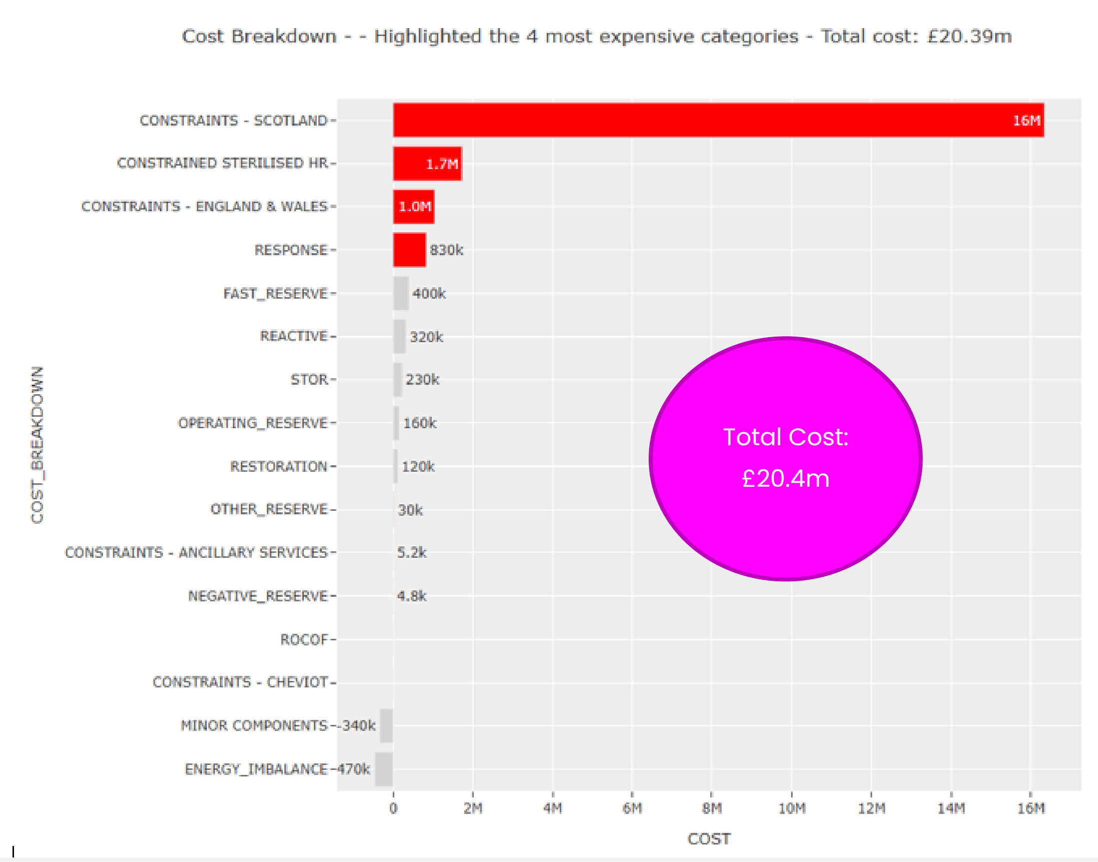
November’s balancing costs were £265.6m which was lower by £65m than the previous month. This included five days with a total cost above £15m (2, 3, 20, 27, 28) less than October which had eight. There were also a further five days in November having a cost over £10m (1, 4, 13, 19, 26). The daily average cost decreased by £1.7m, from £10.5m in October to £8.8m.

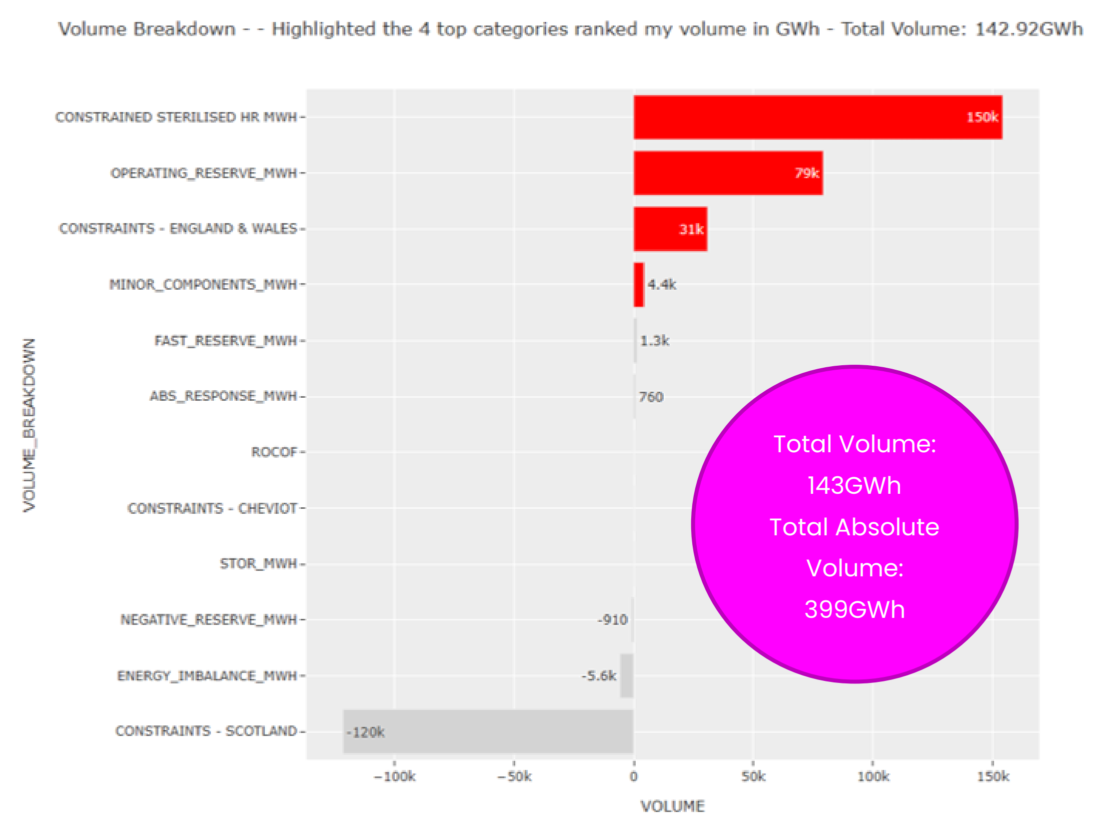
The highest cost day was Monday 3 November, with a total cost of approximately £20.4m, similar to the highest costing day in October. These costs were driven by high levels of wind curtailment for constraint management given a number of outages began on this day with a significant one reducing the B6 boundary.

The lowest cost day was Saturday 8 November, with a total cost of approximately £2.5m slightly lower than the lowest costing day in October at £2.7m. This lowest costing day was closely followed by Friday 7 November with marginally more spend. Both days had very low wind outturn, 113 GWh on the 8 and 98Gwh on the 7 being the second and third lowest outturn days of the month. We saw no wind curtailed on either of these days.

High-Cost Day – 3 Nov 2025

Breakdown of Cost and Volume





November 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.

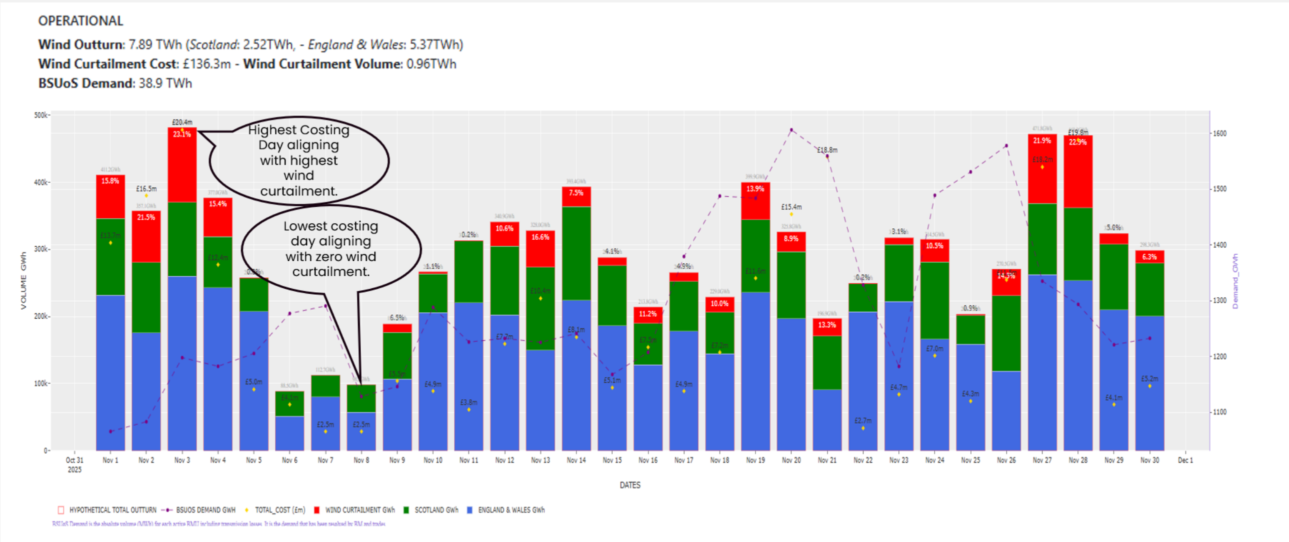
KEY: **Blue bars:** Wind generation in England and Wales

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.

2. Demand Forecasting

Performance Objective

Operating the Electricity System

Success Measure

Continuous improvement in forecasting is vital to ensuring we make informed decisions across all timescales. We will continue to publish our performance in this area through the Demand Forecasting metric (BP2: Metric 1B) and Wind Generation Forecasting metric (BP2: Metric 1C).

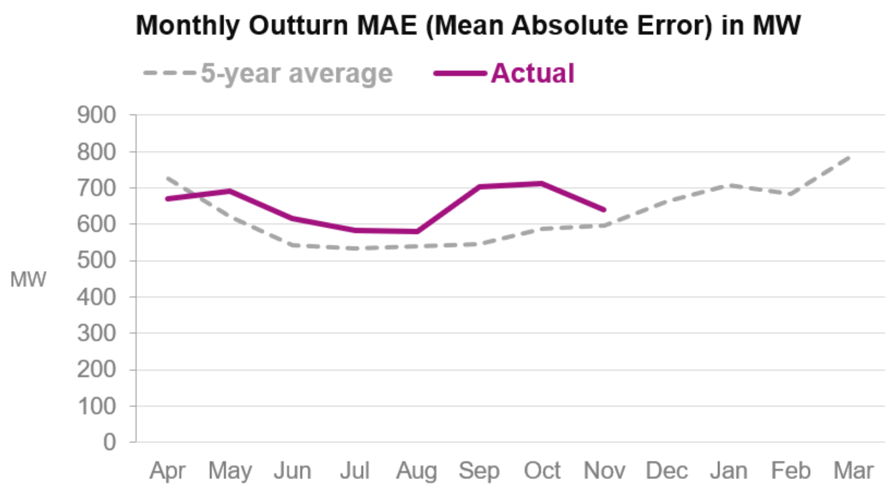
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. BMRS is now known as Elexon Insights.

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.

In order to provide transparency of our performance, we compare each month's actuals to the previous year, and to the average of the previous 5 years' actuals for the same month.

November 2025-26 performance

Figure: 2025-26 Monthly absolute MW error vs Indicative Benchmark



[2] Demand | BMRS (bmreports.com)

Table: 2025-26 Monthly absolute MW error vs Previous 5-year average

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year Average (MW)	727	620	541	532	538	545	588	596	662	707	684	793
Previous year outturn (MW)	687	610	565	528	596	612	578	591	652	735	758	850
Absolute error (MW)	**671**	**692**	**616**	**584**	**579**	**702**	**711**	**641**				

*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5-year average and last year's outturn as an indicator.

Supporting information

In November 2025 forecasting error averaged 641MW, against the previous 5-year average of 596MW. YTD performance is currently 649MW, vs 5-year average of 586MW.

November has been characterised by "some very variable weather and large temperature swings", with the first snowfall landing this Winter along with unseasonal warmer weather.

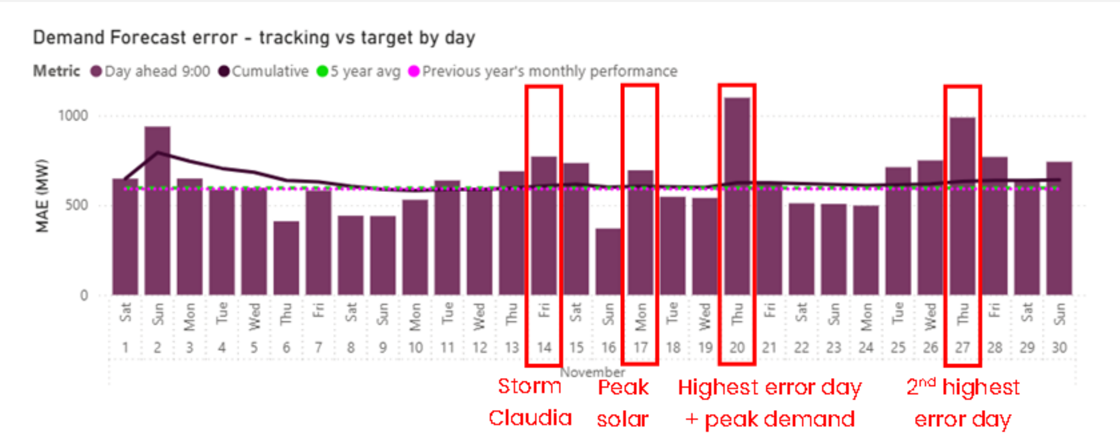
Storm Claudia brought some extra rain to UK, but otherwise the impact was relatively minor.

Solar generation peaked at 8.1GW on 17 November.

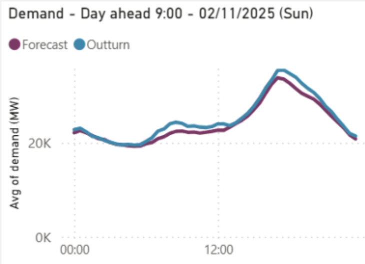
The largest absolute demand error this month was 2.5GW on 28 November, SP28.

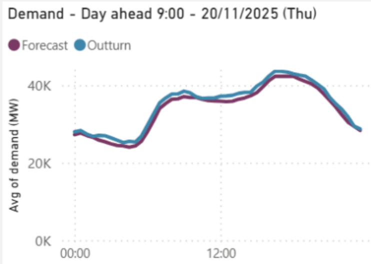
The minimum demand was 17.4GW on 1 November, SP9, while the maximum demand was 43.7GW on 20 November, SP34.

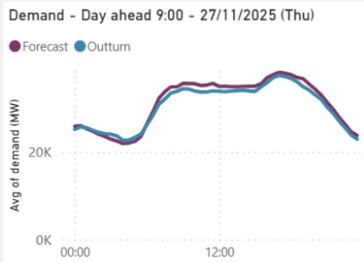
Work is inflight to rebuild the national demand forecast models. These will adopt ML/AI technology and will make use of the latest generation weather data, with an expected release to production in Q1 2026.



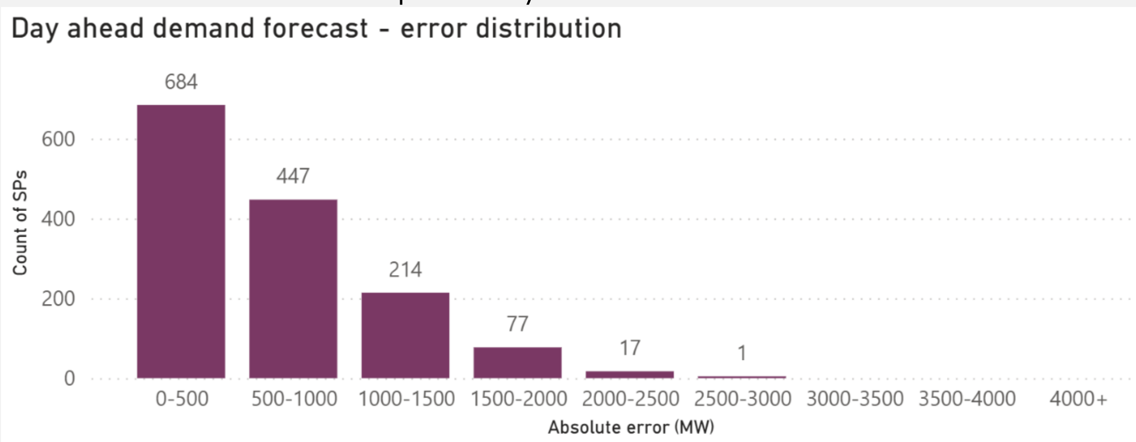
Days of Interest:



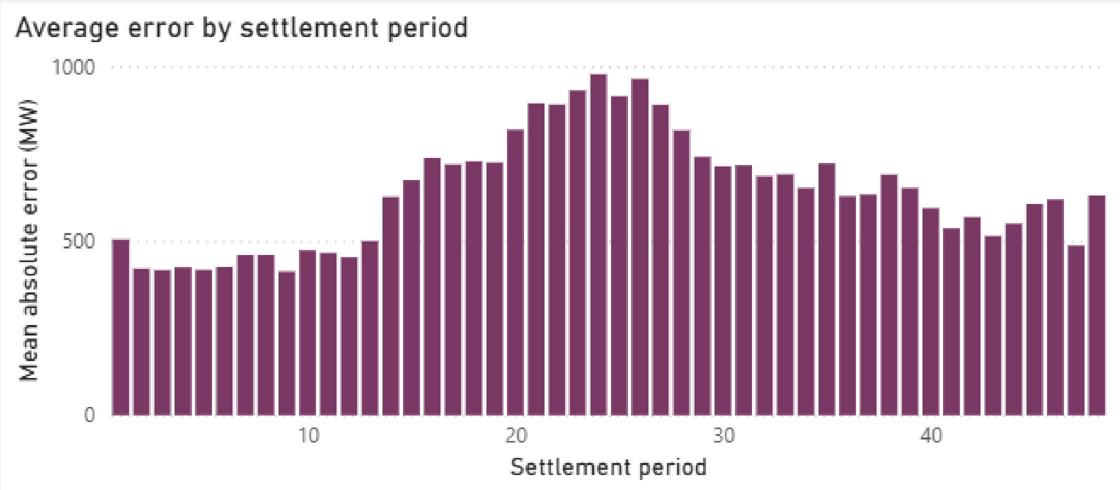




The distribution of settlement periods by error size is shown below:



The distribution of average error by settlement period is shown below:



The days with largest MAE were 2, 20 and 27 November.

Day	Error (MAE)	Major causal factors
2	1099	Temperatures above average. First Sunday after clock change, therefore new models were adjusting. Limited pool of appropriate profile dates available for these two reasons. Some wind error through the day, especially in the morning.

20	988	One of the coldest days of November, with several weather warnings for snow and ice across the country. The ML model had not fully integrated the drop in temperatures and had been significantly under-forecasting the demand. Some embedded wind error in the afternoon.
27	938	Temperatures recovered from the cold spell of the previous 10 days, therefore demand was over-forecast for most of the day. Embedded wind error through the day, especially overnight (1st period).

Missed / late publications

There were no missed/late publications in November.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 6, 18, 19, 20, 21, 25 and 26 November, with an accumulated total of 1277MW procured. These will nominally affect the national demand outturns but are not included in the day ahead forecast.

3. Wind Generation Forecasting

Performance Objective

Operating the Electricity System

Success Measure

Continuous improvement in forecasting is vital to ensuring we make informed decisions across all timescales. We will continue to publish our performance in this area through the Demand Forecasting metric (BP2: Metric 1B) and Wind Generation Forecasting metric (BP2: Metric 1C).

This Reported 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); and
- 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.

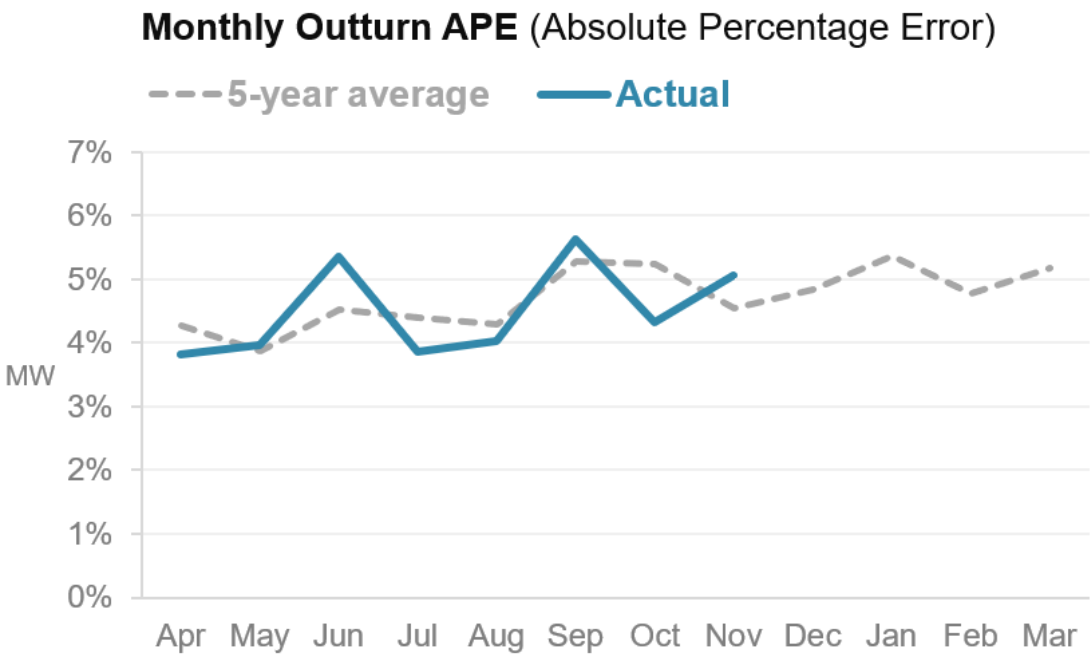
Sites deemed to have withdrawn availability are those that:

- 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.

In order to provide transparency of our performance, we compare each month's actuals to the previous year, and to the average of the previous 5 years' actuals for the same month.

November 2025-26 performance

Figure: 2025-26 BMU Wind Generation Forecast APE vs Indicative Benchmark



In line with the BP2 methodology reported from the BP2 18-Month Report onwards (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).

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Previous 5-year average (%)	4.26	3.87	4.53	4.39	4.3	5.27	5.23	4.55	4.84	5.36	4.78	5.18
Previous year outturn (%)	4.64	3.60	4.72	4.24	4.15	5.04	4.70	3.63	3.86	4.40	3.97	5.20
APE (%)	**3.85**	**4.09**	**5.61**	**3.80**	**4.02**	**5.62**	**4.33**	**5.05**				

*Ofgem will no longer use a benchmark to assess our performance against this Metric however we will continue to report the previous 5-year average and last year outturn as an indicator.

Supporting information

In November 2025, BMU wind forecasting error averaged 5.05%, against the 5-year average of 4.55%. YTD performance is currently 4.56%, vs 5-year average of 4.55%.

November has been characterised by "some very variable weather."

Extreme forecast errors on November 6, 7, 18 and 23, were due to rapidly-changing wind speed forecasts. On all these days, the within-day performance improved significantly, as the weather forecasts adjusted.

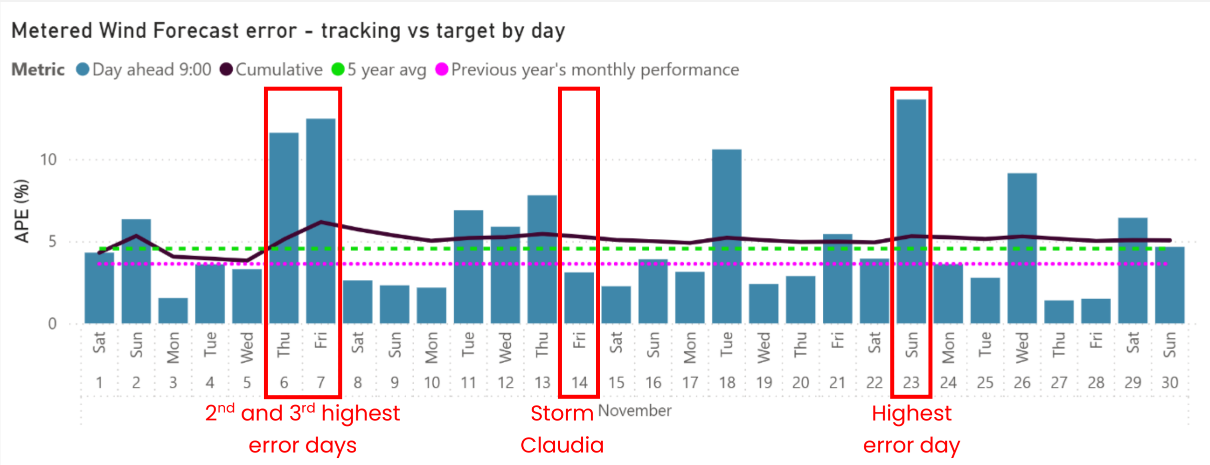
Storm Claudia had minimal effect on wind outturn or performance.

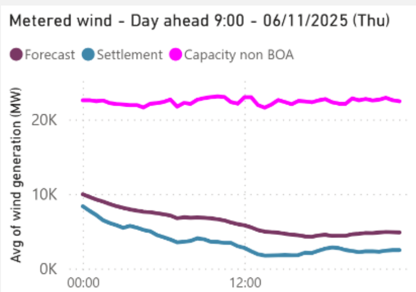
A new GB wind outturn record of 22.7GW was achieved on 11 November, which included both metered and non-metered values. Note: The non-metered contribution is estimated using T0 (closest to real-time) weather forecasts.

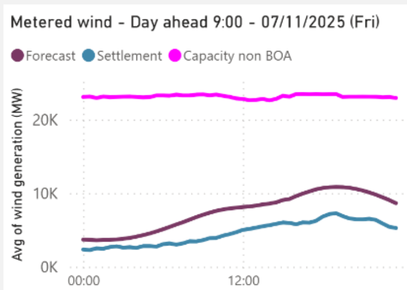
Metric-adjusted wind generation peaked at 17.0GW on 11 November, SP38, while the Wind forecast absolute error peaked at 5.1GW on 26 November, SP44.

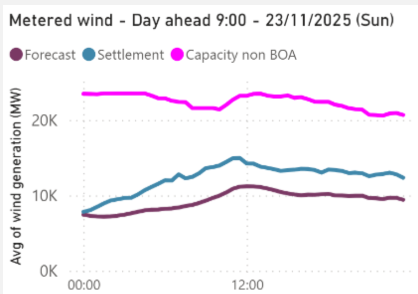
Work is underway to upgrade the wind generation forecast models. These make use of additional weather variables and features added in the new platform.

Days of Interest:

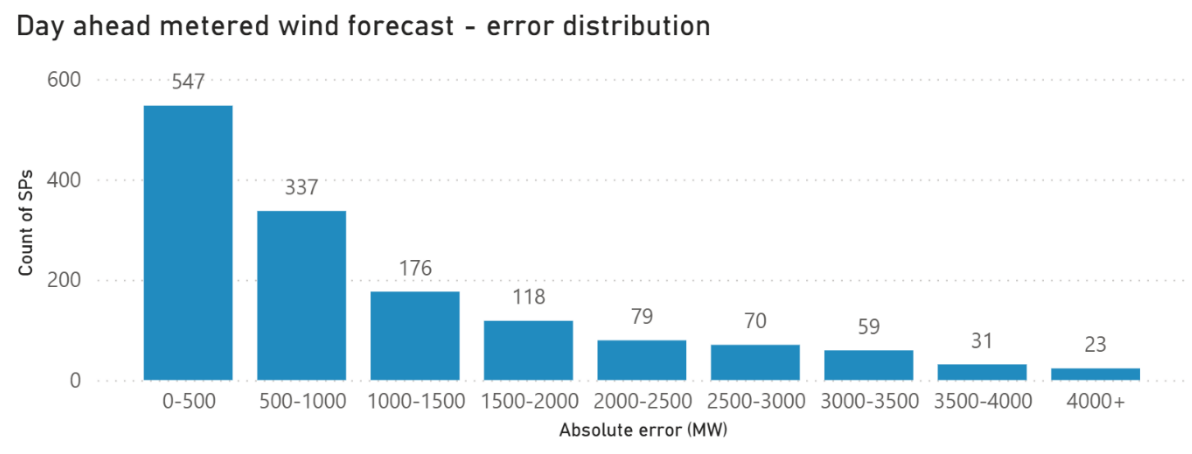








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
6	11.6	Wind speed forecast errors especially at day-ahead stage
7	12.5	Wind speed forecast errors at day-ahead stage
23	13.6	Wind speed forecast errors at day-ahead stage

Missed / late publications

There were no missed/late publications in November.

4. Skip Rates

Performance Objective

Operating the Electricity System

Related Success Measure

In December 2024, we published a skip rate methodology and delivery plan alongside a continuous skip rate measure on our data portal. We will develop this further into a detailed delivery programme and roadmap ahead of BP3, aligning it with our dispatch strategy. During BP3, we will deliver all commitments within our delivery programme and roadmap to reduce skip rates, providing transparency by continuing to report against the skip rate measure.

By the end of BP3, deliver a substantial reduction in skip rates with a target of relative parity across technology types.

Publish timely, accessible, and accurate skip rates data using both the existing five-stage post system action methodology and any updated methodology agreed with the industry.

Work closely with industry to develop and set an absolute numerical target for skip rates within the BP3 period.

Develop and share a methodology to measure the skip rate of actions taken to manage system constraints.

Share Platform for Energy Forecasting (PEF) and skip rate data, as well as issuing data associated with other strategic platform energy releases.

NESO has an obligation to operate a safe, reliable and efficient system. In consultation with industry, we have developed the All Balancing Mechanism (All BM) skip rate and Post System Action (PSA) skip rate as measures of dispatch efficiency. A skip occurs when a non-economic dispatch decision is made due to the NESO Control Room sending an instruction via BOA (Bid Offer Acceptance) at a higher price than an alternative could have been taken. Some skips are unavoidable due to asset dynamics and transmission limits while others may occur as a result of optimising the lowest cost over the day.

Our goal is to enhance transparency on our dispatch decision making and deliver a substantial reduction in skip rates that results in, as far as is practicable, relative parity across technology types by the end of BP3.

This Reported Metric measures the skip rate for bids and offers based on stage 5 of the Post System Action (PSA) methodology and will also include any updated methodology agreed with industry. More information on the skip rate definition and methodology can be found here.

Table: 2025-26 Monthly % PSA Skip rate Offers and Bids

The numbers in these tables have changed following a bug fix implemented to ensure inaccessible volume from long notice units does not show as skipped. Where figures have changed, their previously reported values are shown in red in the bottom of the box.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers	43%	35%	33%	36%	31%	32%	30%	33%				
Bids	43% 45%	42% 43%	47% 51%	46% 47%	39% 40%	42% 45%	40% 45%	35%				
Combined	42% 44%	39% 40%	38% 40%	42% 42%	35% 36%	36% 38%	34% 36%	34%				

Table: 2025-26 Monthly Skip rate Offers and Bids volumes (GWh)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers – skipped volume	63	71	116	78	86	116	133	103				
Offers – in merit Energy volume	148	205	356	215	279	359	437	309				
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971	1084	878				
Bids – Skipped volume	141 150	148 154	111 118	127 130	122 128	102 109	93 106	108				
Bids – in merit Energy volume	336	352	234	277	316	243	234	310				
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488	1815	1597				
Combined Bid & Offer – skipped volume	204 213	219 225	227 234	205 208	208 214	218 226	226 239	211				

Supporting information

NOVEMBER UPDATES

Skip Rate Monitor

During November we have kicked off several initiatives to drive utilisation of the Skip Rate Monitor tool within our Control Room. This includes continuing training sessions on the tool, designing real time alerts, and regular engagement with ENCC engineers. Training sessions on the monitor will continue until mid-December.

Industry Engagement

We hosted an industry webinar on 3 November where we shared project updates on materiality, GC0166, Dispatch Strategic Review, Root Cause Analysis, skips behind constraints, and a skip rate target. We have engaged with industry groups on the aims and ideas for a skip rate target. We received a range of views that we are using to inform our proposal for a target. We also presented a programme overview at the Balancing Programme event on 18 November where we also asked for industry views on a target.

Skips Behind Constraints

Work has continued to develop a methodology to measure skips behind constraints. This method will be shared with industry in January 2026 with the view to agree a method with industry before end of financial year.

NOVEMBER PERFORMANCE

The Offer skip rate has increased from October (30%) to November (33%) with skipped volume reducing due to a lower volume of energy offer actions taken in November. The Bid skip rate has reduced from October (40%) to November (35%), and the skipped volume has increased from 93GWh to 108GWh. The combined bid and offer skip rate has remained steady at 34%.

The first two weeks on November saw some of the lowest weekly skip rates this year (29% for both W/C 03/11 and 11/11). This was largely driven by the night shifts where we saw:

- Low number of active constraints
- Conventional generation run for system reasons, leading to high levels of inertia
- Some demand and wind forecast errors leading to significant amounts of energy volume required

The skip rate increased in the final 2 weeks of November. This was largely driven by evening and night shifts. Generally, we saw:

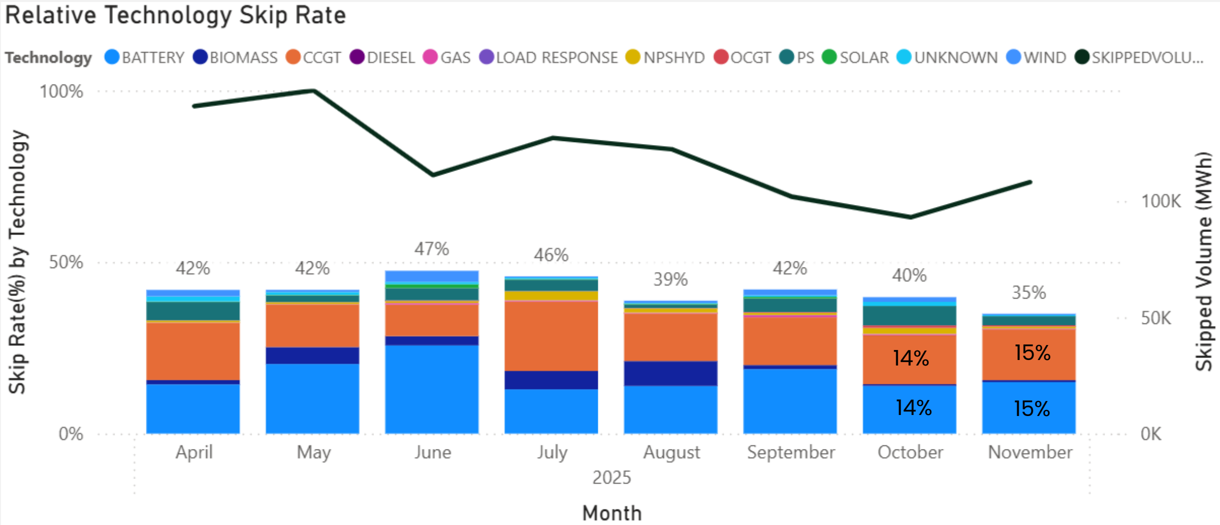
- Wind outturn variability
- Delayed desynchs to manage the system

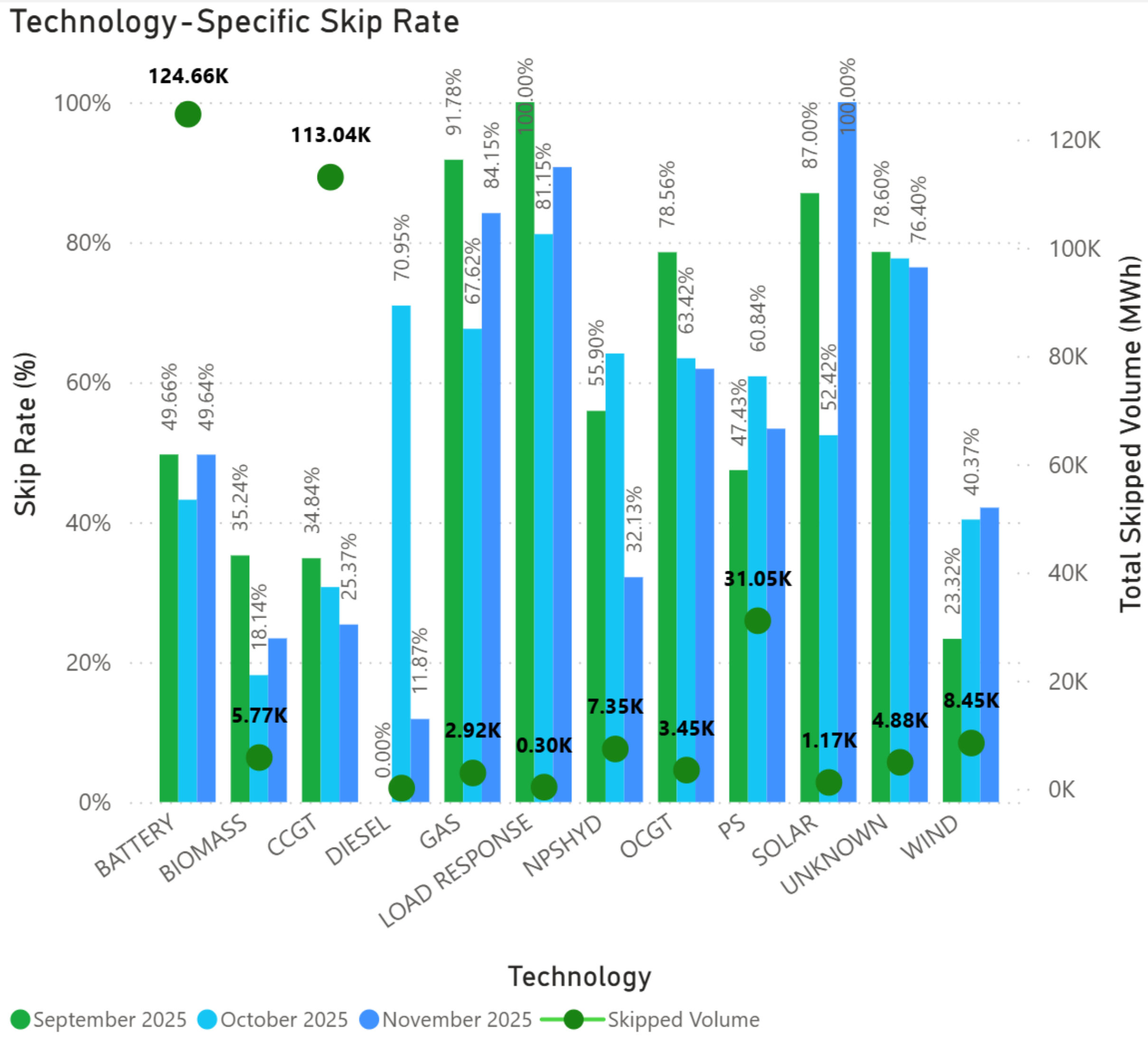
- Energy wind bids
- Active constraints
- Interconnector and demand forecast errors

Bids

CCGTs accounted for a higher proportion of skipped volume in November (15%) compared to October (14%) and the Technology Specific skip rate for CCGTs has decreased from 31% to 25%. Batteries account for a higher proportion of the skip rate in November (15%) compared to October (14%) and the Technology Specific skip rate has increased from 43% to 50%. This has been driven by a reduction in the amount of battery volume that was in merit through the month, despite lower skipped volume and similar accepted in merit volume.

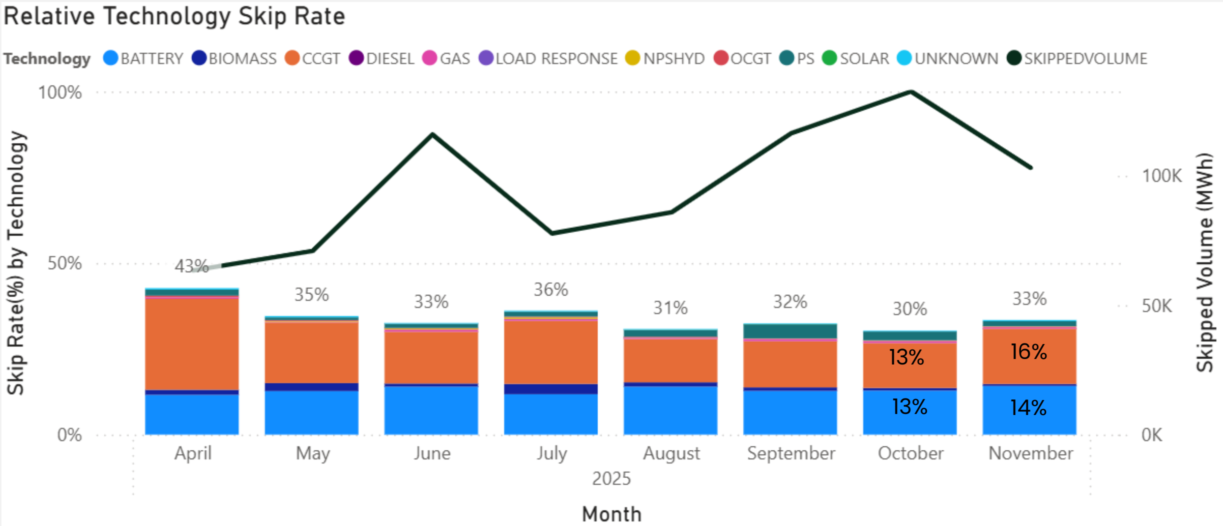
Note – technology specific skip rates can be particularly high or low when there is a small amount of volume in merit for a given technology type.

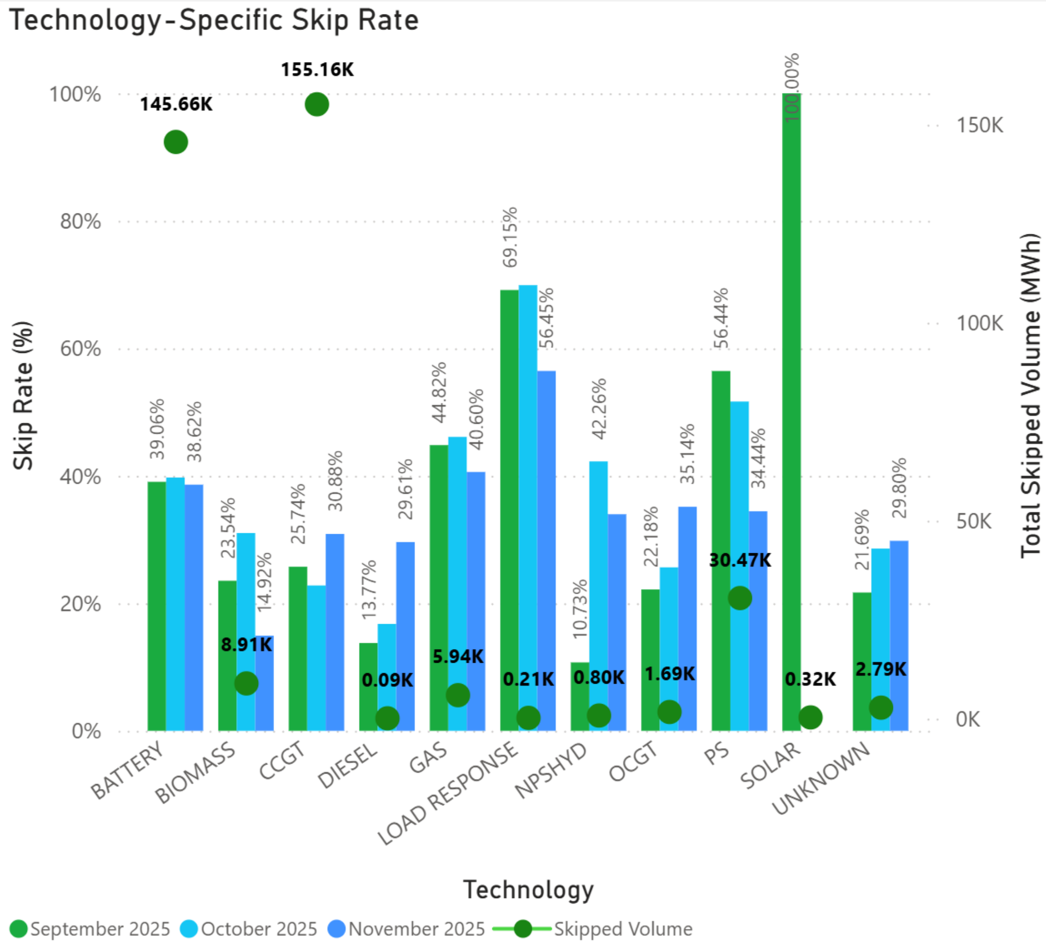




Offers

CCGTs account for a higher proportion of skipped volume in November (16%) than October (13%), and the Technology Specific skip rate has increased from 23% in October to 31% in November. Batteries account for the higher proportion of skipped volume in November (14%) than October (13%), and the Technology Specific skip rate has decreased from 40% in October to 39% in November.





Note: In these graphs 'Gas' refers to gas reciprocating units, which are typically small, aggregated units. 'Load Response' is based on the fuel type category used by Elexon. These are typically Demand Side Flexibility (DSF) units. Work is ongoing to publish a dedicated dataset showing skip rates for DSF units. This will be published in early December.

5. Carbon intensity of NESO actions

Performance Objective

Operating the Electricity System

Success Measure

By the end of 2025, we will demonstrate our ability to operate the system carbon-free whenever electricity markets provide a zero-carbon solution. We will measure this through reporting against the Zero Carbon Operability Indicator (BP2: RRE 1F) and the Carbon Intensity of NESO Actions (BP2: RRE 1G).

This Reported Metric 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 Zero Carbon Operability Indicator (previously RRE 1F) and Carbon intensity of NESO actions (previously 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. We provide more information about our operability challenges in the Operability Strategy Report.

November 2025-26 performance

Figure: 2025-26 Average monthly gCO2/kWh of actions taken by NESO (vs 2024-25)

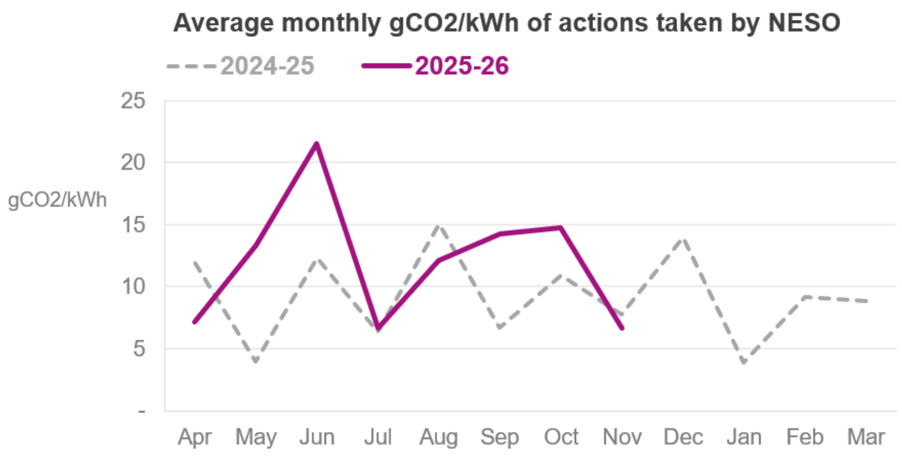


Table: Average monthly gCO2/kWh of actions taken by NESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	7.16	13.36	21.53	6.64	12.11	14.22	14.75	6.68				

Supporting information

We report the average monthly gCO_2/kWh of actions taken by NESO in line with reporting requirements. Alignment of the ZCO technologies with the CP30 technologies would see the inclusion of biomass and exclusion of CHP's, which is yet to be reflected in these data.

In November, the average monthly carbon intensity from NESO actions was 6.68g/CO_2/kWh. This is 8.07g/CO_2/kWh lower than October and 5.38g/CO2/kWh lower than the YTD average of 12.06g/CO_2/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 48.72g/CO2/kWh which took place on 2 November at 13.30. This is 35.1g/CO_2/kWh lower than the highest point in October 2025 of 83.82g/CO_2/kWh.

On 2 November unconstrained transmission connected wind output was high and it was expected that up to 2.8GW of wind would need to be constrained off to meet security requirements for congestion in Scotland.

6. Security of Supply

Performance Objective

Operating the Electricity System

Success Measure

As the electricity system in Great Britain evolves, we will transform the capabilities of our people, processes and systems and continue to deliver economic and efficient real-time operation of the electricity transmission system, as measured through the Security of Supply reporting evidence (BP2: RRE 1I).

This Reported Metric 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
$49.2 \leq f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \leq 48.8$	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.

November 2025-26 performance

Table: Frequency and voltage excursions (2025-26)

	2025-26											
	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				
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	0	0				
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	1	0	0	1	0	0				

Supporting information

No reportable voltage or frequency excursions during November.

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

7. CNI Outages

Performance Objective

N/A

Success Measure

N/A

This Reported Metric 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.

November 2025-26 performance

Table: 2025-26 Unplanned CNI System Outages (Number and length of each outage)

Unplanned	2025-26											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0				
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0				

Table: 2025-26 Planned CNI System Outages (Number and length of each outage)

Planned	2025-26											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 215 mins	1 outage 115 mins	0	0	1 outage 150 mins				
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0				

Supporting information

In November 2025 there was one planned CNI system outage. The outage was to carry out regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

This change took place on 27 November, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

On the day of the outage, our control rooms are again consulted to confirm that conditions remain suitable to proceed with the change or, if required, whether the change must be rescheduled.

Additionally, on the day, notifications are posted to the industry, via BMRA, when the outage is due to start, and when it is complete.

There were no other planned outages during November.

There were no unplanned outages during November.

National Energy System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

www.neso.energy

NESO
National Energy
System Operator