24 February 2026

Monthly Incentives January 2026 Report

Business Plan 3 (2025-26)

NESO
National Energy
System Operator

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 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 January 2026:

	Reported Metric	Performance
1	**Balancing Costs**	**£303m**
2	**Demand Forecasting**	Forecasting error of **662MW**
3	**Wind Generation Forecasting**	Forecasting error of **4.99%**
4	**Skip Rates**	Post System Action (PSA) Offers: **28%** Bids: **40%** Combined: **31%**
5	**Carbon intensity of NESO actions**	**10.71gCO_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.

January 2026 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

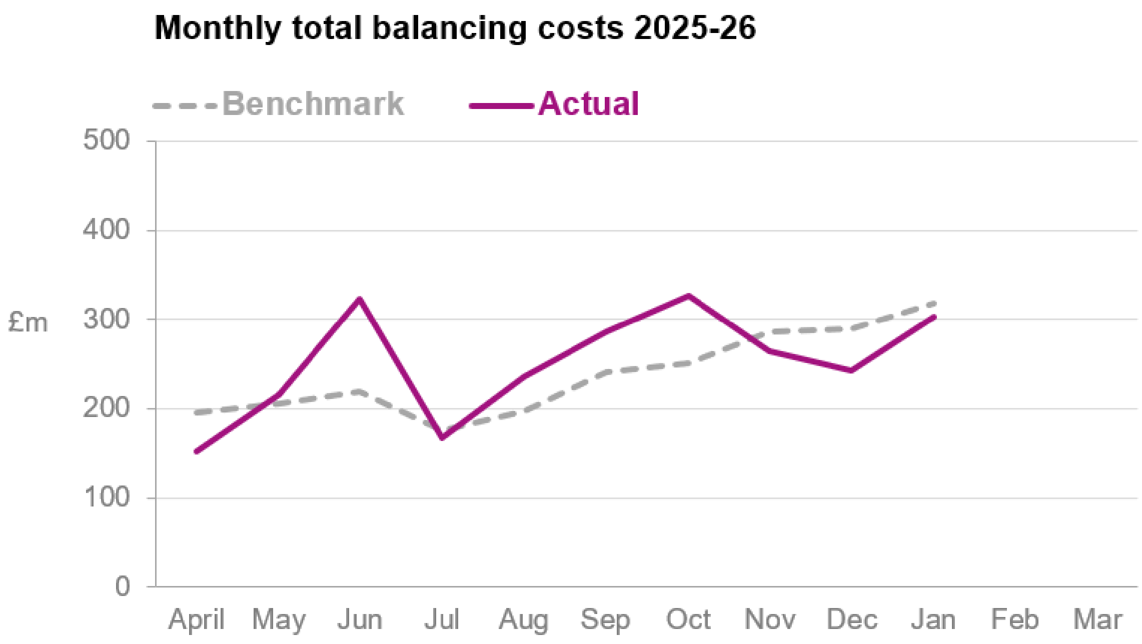


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

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	8.3	8.6			59.7
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72	77	82	75	100			n/a
Benchmark*	195	206	219	176	197	241	251	286	289	318			2378
Outturn balancing costs[1]	**152**	**215**	**324**	**167**	**236**	**287**	**326**	**265**	**242**	**303**			**2517**

[1] Outturn balancing costs exclude 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

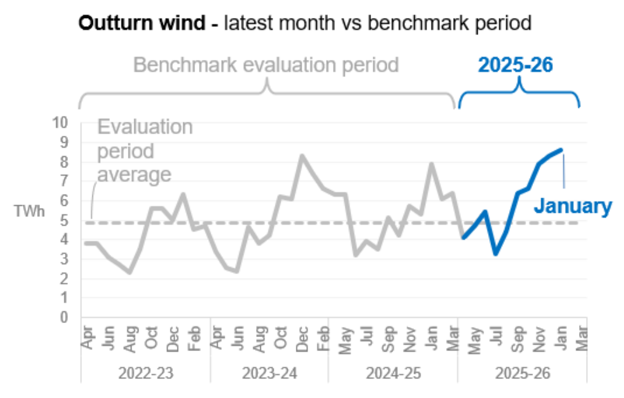
BALANCING COSTS METRIC & PERFORMANCE

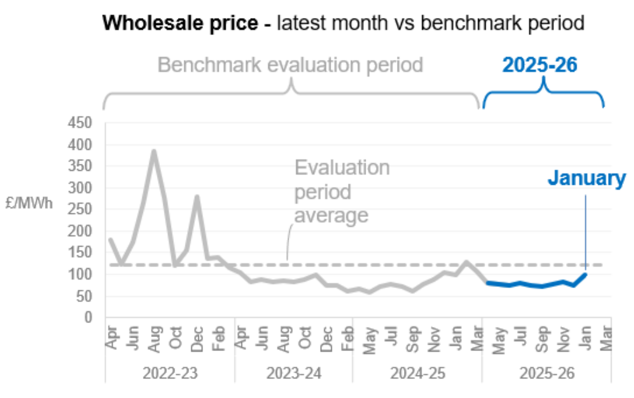
This month's benchmark

January's benchmark of £318m is £29m higher than December 2025 and reflects:

- An outturn wind figure of 8.6 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 December 2025's figure (8.3 TWh).
- An average monthly wholesale price (Day Ahead Baseload) that has increased compared to December 2025 (from £75.4/MWh to £99.6/MWh) but is lower than the same period last year. It falls below the evaluation period average.

An increase in average monthly wholesale price as well as an increase in wind outturn has led to a significant increase in the benchmark from December.





Balancing Costs – Overview

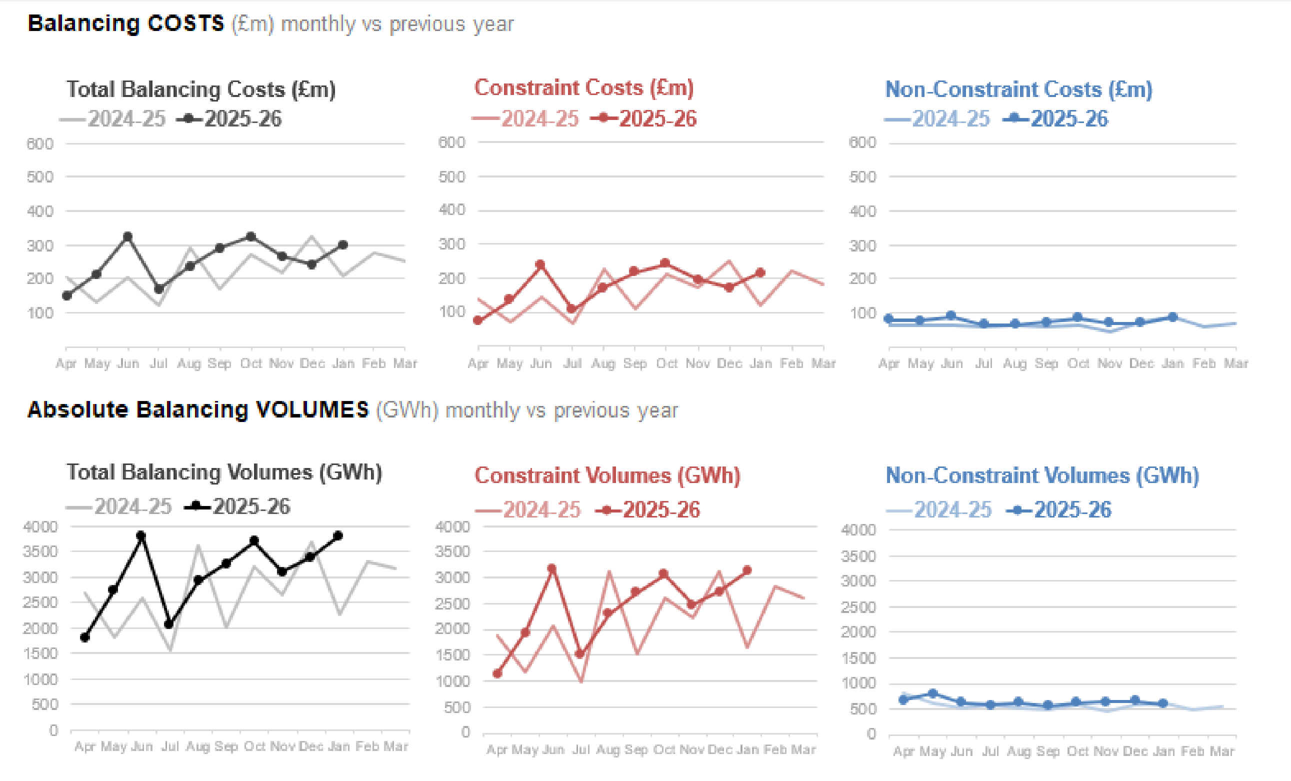
The total balancing cost for January was £302.7m, which is £15.3m (~5%) below the benchmark.

January saw an increase in wind outturn to 8.6TWh compared to December at 8.3TWh, the highest wind outturn observed so far this Financial Year, and the highest-ever recorded wind outturn. The rise in wind outturn was driven by large increases across Scotland, despite some marginal decreases observed across England & Wales. Particularly windy conditions were brought about by the two storms during the month, Storm Goretti, impacting the UK on 8-9 January, and Storm Chandra, impacting the UK on 26-27 January. The particularly high monthly wind outturn corresponded with the second-highest wind curtailment seen over the past year and represents a 121% increase on wind curtailment volumes in January 2025. Average demand was higher than December throughout the whole day, but higher wind levels meant significant curtailment was still required, and with significantly higher power prices this led to higher overall costs in January.

Voltage constraint costs have decreased significantly in January due to colder than average temperatures driving high demand and thus more self-dispatch of units providing reactive power support, with less units being procured through the Balancing Mechanism. Similarly, more units self-dispatching rather than BM procurement led to a slight decrease in inertia costs.

Non constraint costs have increased by £19m despite a decrease in the overall volume of actions compared to December. This is attributable to a combination of the increase in average clearing prices for frequency response services, an increase in wholesale prices, and an increase in Fast Reserve procurement due to tighter margins brought about by winter conditions.

Average wholesale prices have increased by £25/MWh in January, largely due to colder than average temperatures and increased demand. The volume weighted average (VWA) price of bids was £4.5/MWh, which is less expensive than December's price of -£7.2/MWh. The less expensive bid prices were offset by an increase in the VWA price for offers, which rose from £106.0/MWh in December to £129.5/MWh in January, signalling more expensive replacement energy for wind curtailment.

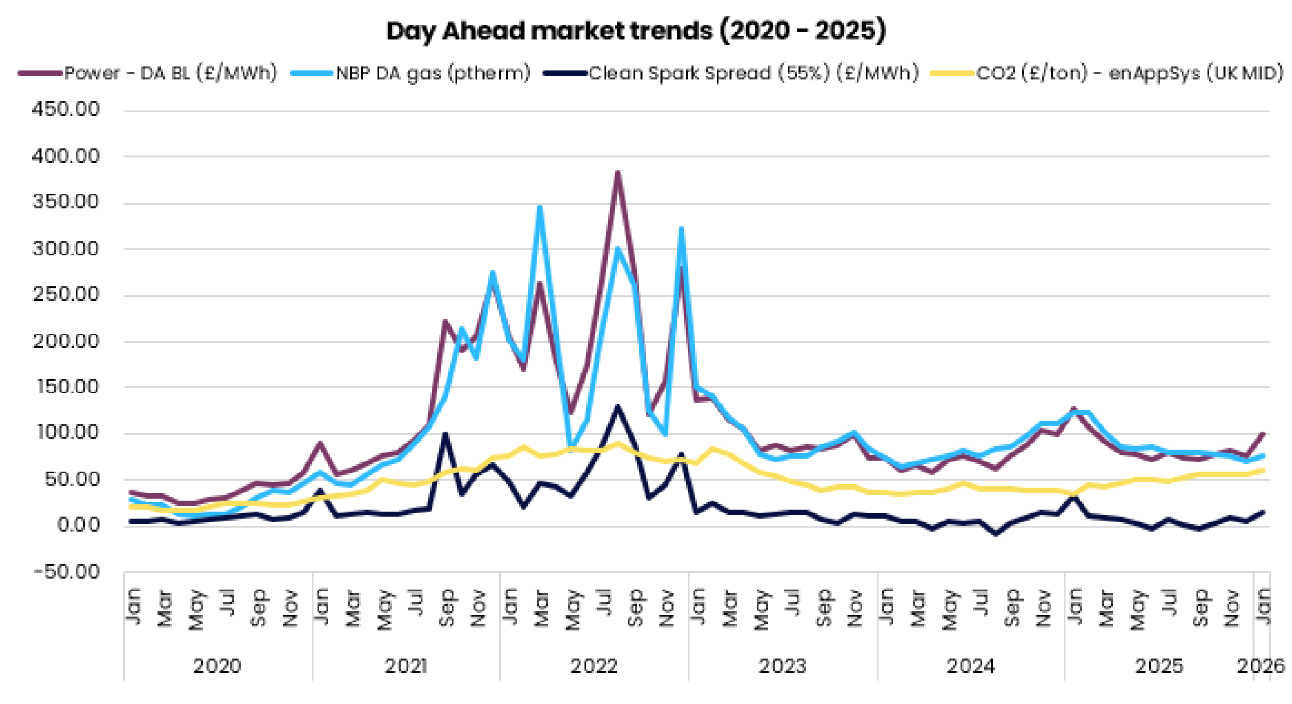


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

In January, power and gas prices increased compared to the previous month, up to £99.60/MWh and 76.20p/therm, with carbon prices also seeing a slight increase up to £61.28/ton. Market prices were influenced by a variety of factors during January, including colder than average temperatures and an uptick in demand since December, though these drivers may have been somewhat offset by the strong wind outturn brought about by the two storms experienced over the month.



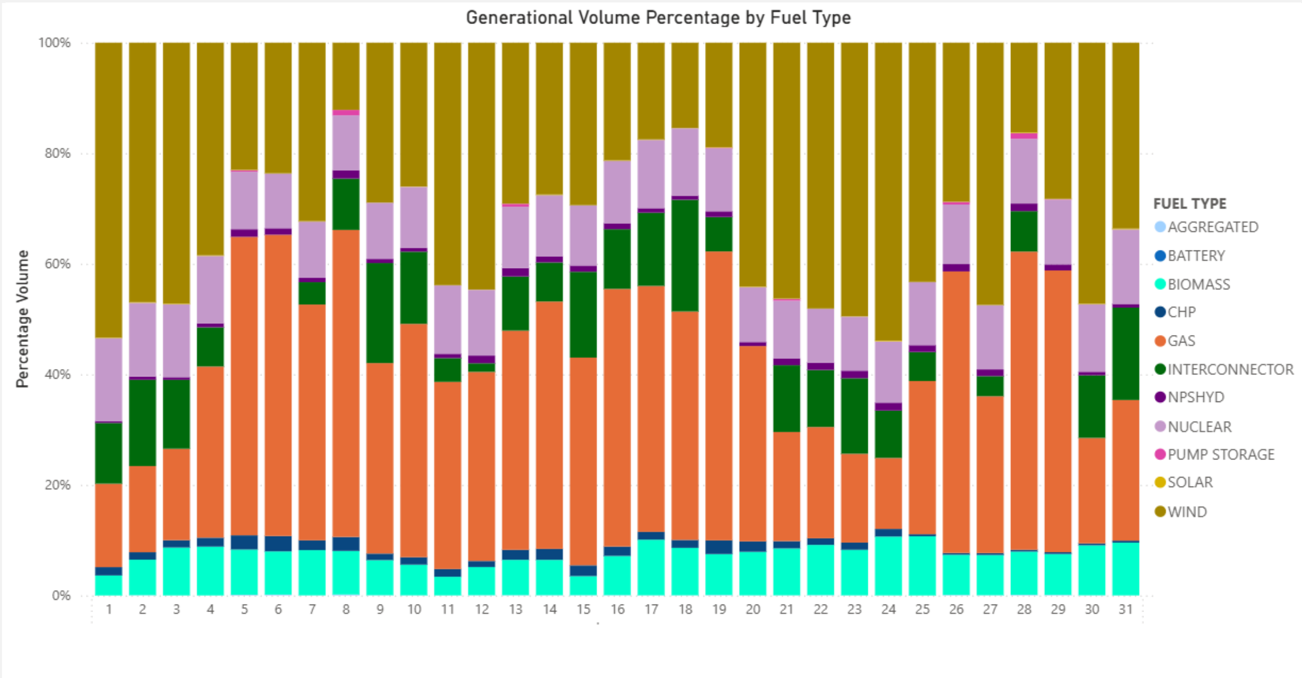
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

In January gas was the largest contributor to electricity generation, making up 36% of the total mix, followed by wind, which saw a drop from December down to 34%, and with nuclear in third place despite falling from 12% in December to 11% in January. This pattern was overall consistent with December, though with a significant increase in contribution to overall generation mix from gas (28% to 36%) and a notable decrease from interconnectors (13% to 9%), with nuclear displacing as the third largest contributor to the mix.

Despite higher overall wind outturn in January, wind dominated the daily generation mix less consistently than in December, with January experiencing eight days where wind generation was less than 25% of the total daily generation (5, 6, 8, 16, 17, 18, 19, 28), compared to just five days in December.

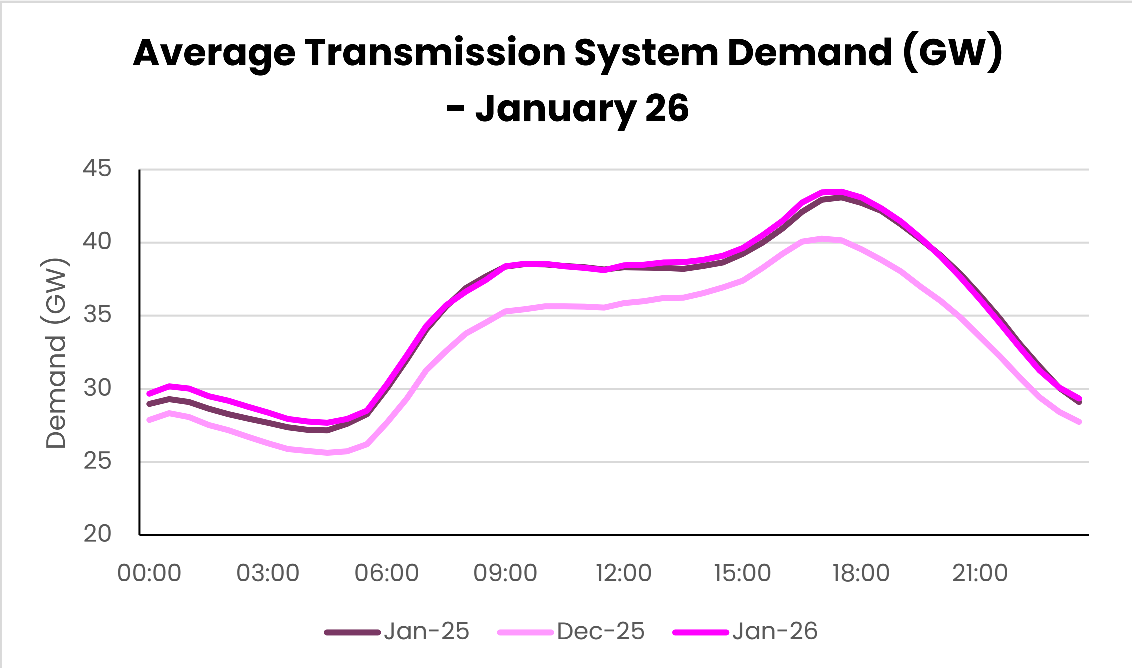
However, we had two days where wind generation was above 50% of total generation which were on the 1 & 24 of January, with the highest percentage being on the 24 January at 54%. Average temperatures were colder in the first half of the month, which coincided with increased national demand and gas plant requirement; 5 January experienced the highest demand for the month with gas generation making up 54% of the total mix (third-highest for the month).



*Generation mix includes exports from interconnectors.

Transmission System Demand

In January the average Transmission System Demand (TSD) was in line with January 2025 throughout most of the day, except for the early morning hours where it was higher in 2026, and elevated on December 2025 throughout the whole day. This was due to factors including increased hours of darkness and colder than average weather. January 2026 also saw low embedded solar output, pushing more demand onto the transmission system. Economic and market drivers likely also played their part, with lower year-on-year wholesale power prices reducing incentives for demand-side curtailment.

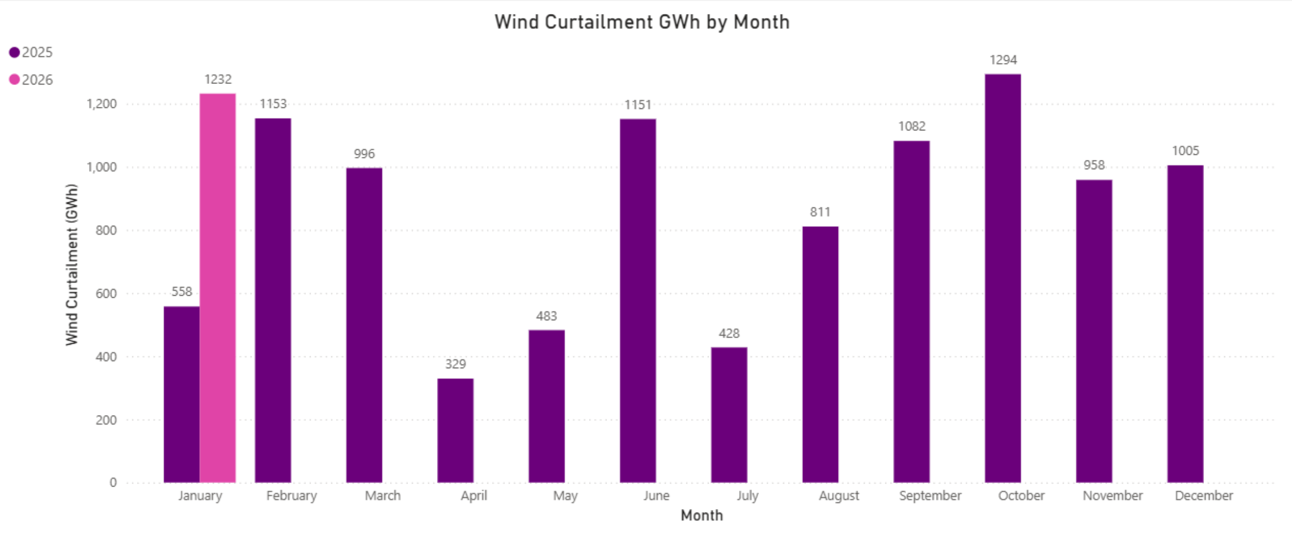


Wind Outturn

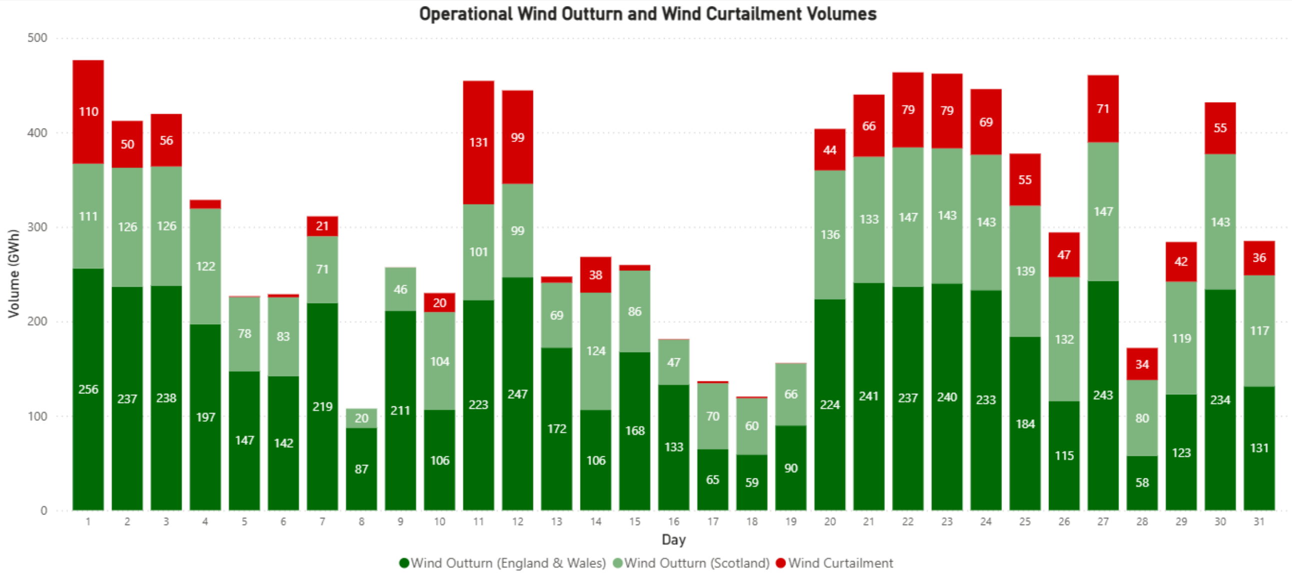
January started off cold, with below average temperatures across the country for the first week as an Arctic airmass approached from the north. By 8 and 9 January, Storm Goretti brought strong, damaging winds to the UK, triggering the first red wind warning of 2026. The rest of January was characterised by slightly below average temperatures and wetter than usual conditions expected at this time of year. The month ended with Storm Chandra impacting the southwest, bringing strong winds again on 26 and 27.

Overall wind outturn rose from 8.3TWh in December to 8.6TWh in January; this made January 2026 the highest-ever recorded wind outturn and represents a 41% increase on January 2025. The rise in overall wind outturn was predominantly attributable to the significant outturn experienced in Scotland, rising by 23% (2.6TWh to 3.2TWh), in contrast with a marginal decrease of 3.6% seen across England & Wales (5.6TWh to 5.4TWh), resulting in a net increase of 3.6% across Great Britain compared to the previous month.

There was a 22.6% increase in the volume of wind curtailment compared to the previous month, which is associated with a corresponding rise in overall wind outturn. There were variable weather conditions throughout the month, with high wind curtailment seen intermittently across the whole month, in contrast to December which was characterised by very low or no wind curtailment across the latter half of the month. The days with the highest volume of wind curtailment were seen at the beginning and middle of the month; on 11 January (131GWh), 1 January (110GWh), and 12 January (99GWh).



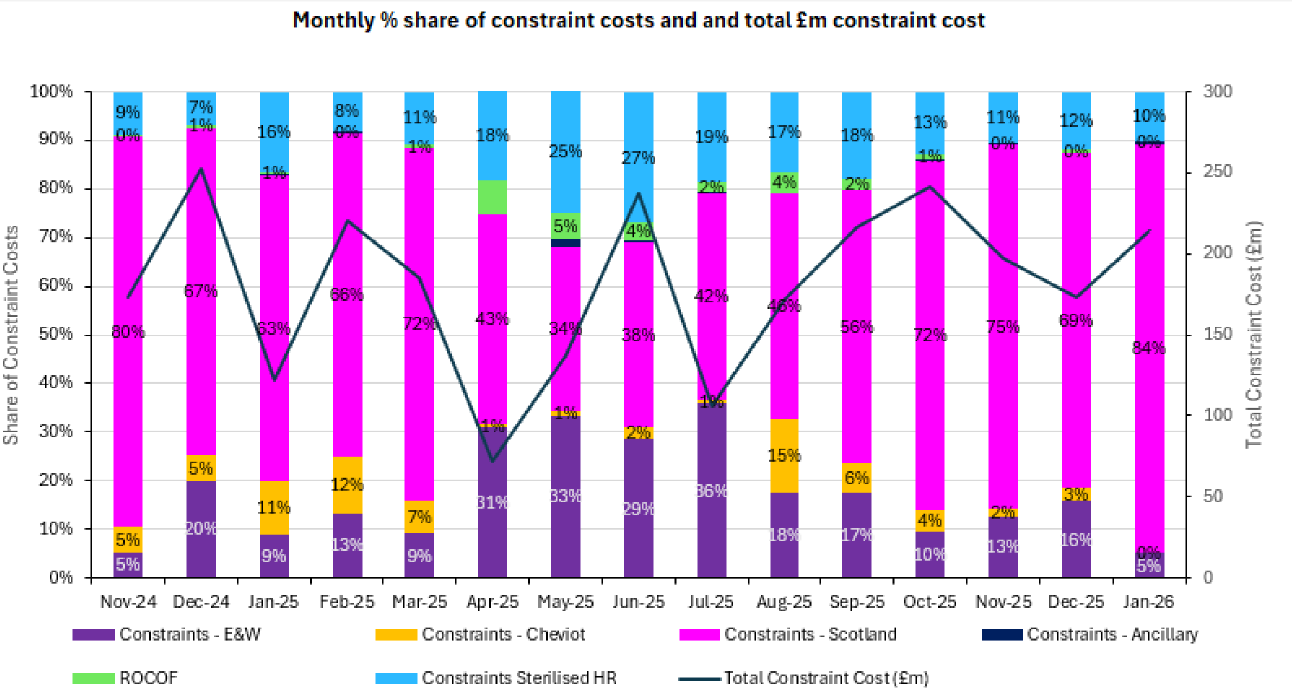
The day with the highest volume of wind curtailment occurred on Sunday 11 January with 131 GWh. There was a total wind outturn of 455 GWh on this date, making it the fifth-highest outturn of the month. This was also the highest cost day of the month.



Constraints

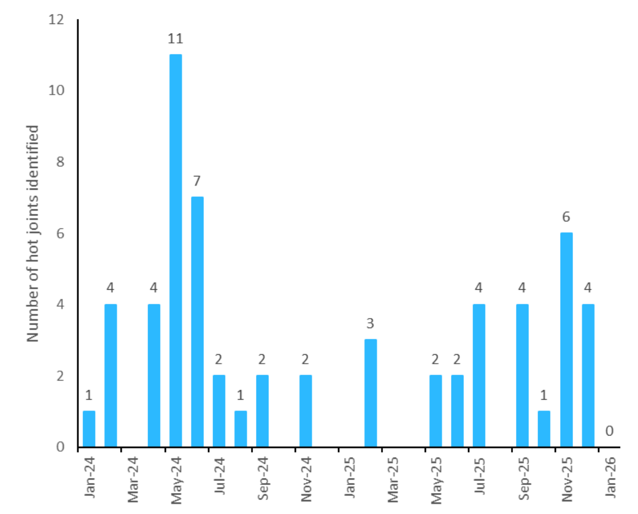
Constraint costs increased from £172.7m in December to £214.7m in January, an increase of £42m. England and Wales saw a decrease in constraint costs of £16.4m, along with Cheviot which saw a small decrease of £4.6m. Most other areas saw an increase with the most significant being Scotland with a £61.1m increase in cost compared to December and making up 84% of the monthly share of constraint costs.

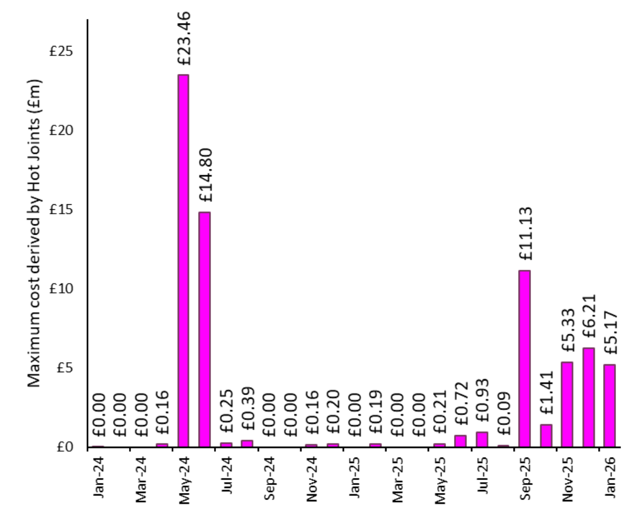
Wind levels across England & Wales decreased slightly, whilst outturn in Scotland increased significantly in January and corresponded with an increase in wind curtailment. An increase in average demand across the whole day in January compared to December was also offset by an increase in power prices, facilitating the overall higher cost of managing constraints.



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 January no hot joints were identified. However, those reported in December 2025 haven't been resolved yet, resulting in additional cost impact during the current month. The estimated maximum cost to the system for these hot joints was approximately £5.2 million during the current month.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): January 2026 vs December 2025

		(a) Dec-25	(b) Jan-26	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	0.6	-0.2	(0.8)	
	Operating Reserve	10.6	5.4	(5.2)	
	STOR	4.5	7.3	2.8	
	Negative Reserve	1.1	2.5	1.4	
	Fast Reserve	15.8	20.9	5.2	
	Response	19.5	21.1	1.6	
	Other Reserve	1.5	1.0	(0.4)	
	Reactive	12.1	11.4	(0.7)	
	Restoration	4.1	10.2	6.1	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	-0.7	8.4	9.0	
Constraint Costs	Constraints - E&W	27.2	10.9	(16.4)	
	Constraints - Cheviot	4.6	0.0	(4.6)	
	Constraints - Scotland	119.3	180.4	61.1	
	Constraints - Ancillary	0.2	1.3	1.2	
	ROCOF	0.7	0.5	(0.2)	
	Constraints Sterilised HR	20.7	21.6	0.9	
Totals	Non-Constraint Costs - TOTAL	69.0	88.0	19.0	
	Constraint Costs - TOTAL	172.7	214.7	42.0	
	Total Balancing Costs	**241.7**	**302.7**	**61.0**	

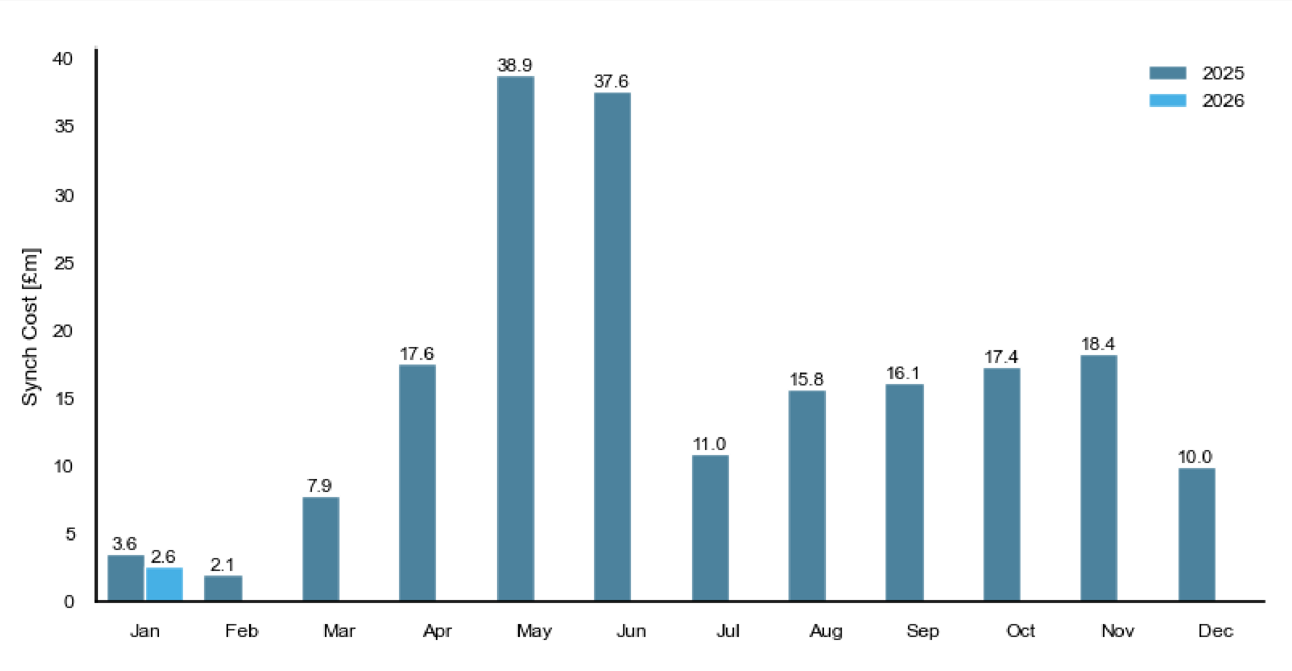
As shown in the totals from the table above, constraint costs increased by £42m and non-constraint costs increased by £19m which results in an overall increase in costs of £61m compared to December 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£56.6m **Constraint – England & Wales: -£16.4m** **Constraint Sterilised Headroom: +£0.9m** Overall constraint costs increased by £42m. This was due to a combination of a 136GWh increase in wind curtailment volumes, a 33% increase in power prices, and a 393GWh increase in the absolute volume of constraint actions taken. **ROCOF: -£0.2m** The decrease in costs can be attributed to a 23GWh decrease in absolute volume of inertia procured, because of a higher proportion of synchronous generation in the mix.	**Constraints – Scotland & Cheviot: +£90.3m** **Constraints – England & Wales: -£0.0m** **Constraints Sterilised Headroom: +£1.6m** Constraint costs across GB have increased by £92.9m compared to January 2025. Power prices in January 2026 decreased compared to January 2025 but were offset by a 674GWh increase in wind curtailment volume, an increase of 121%. **ROCOF: -£0.3m** The decrease in costs can be attributed to a 14GWh decrease in absolute volume of inertia procured, because of a higher proportion of synchronous generation in the mix.

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

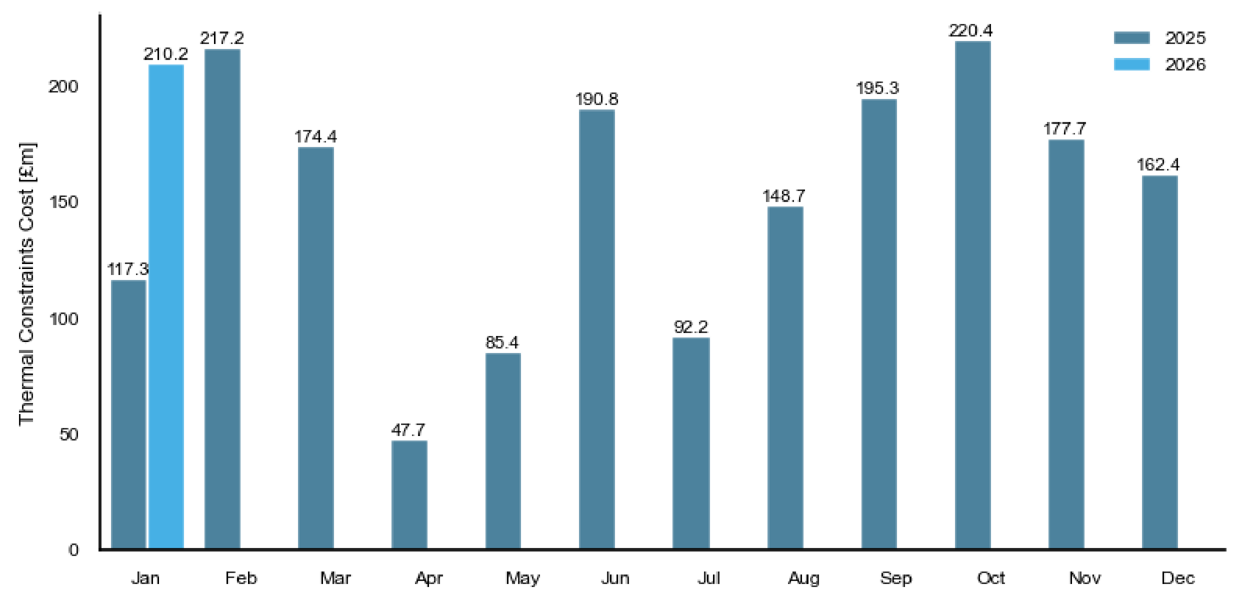
Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support. In January, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £2.6m. This represents a decrease of approximately £7.4m compared to December 2025 and is £1m lower than the same period last year (January 2025).



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 spend. The reduction in voltage costs during the month reflects higher demand alongside a low level of system outages.

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

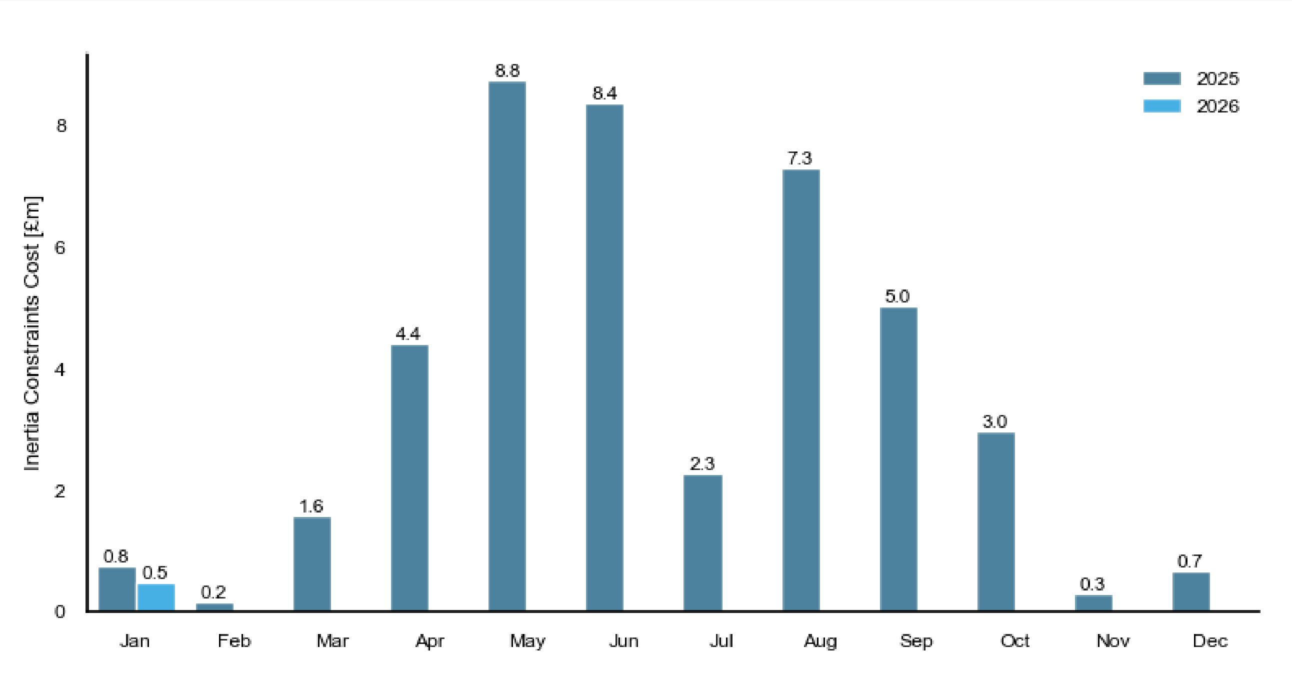
Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints 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 January, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £210.2m, reflecting an increase in costs of over £47.8m (29.4%) compared to the previous month (£162.4m). When compared to the same period last year (£117.3m in January 2025), the cost rose by £92.9m (79.2%).



January 2026 saw an increase in thermal constraint costs and was largely driven by an increase in wind curtailment (particularly in Scotland). Wind curtailment increased from 1005GWh in December to 1232GWh in January, which is a 22.6% increase, and increased by 120.8% (674GWh) when compared to January 2025. Economic drivers such as the 33% increase in power prices further contributed to the significant increase in 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 January, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £0.5m, resulting in a decrease of £0.2m compared to December 2025 and £0.3m lower than January 2025.



The inertia expenditure fell slightly partly down to the high demand in January 2026, as a result of colder than average weather, thus leading to a higher volume of self-dispatching generation fulfilling inertia requirements.

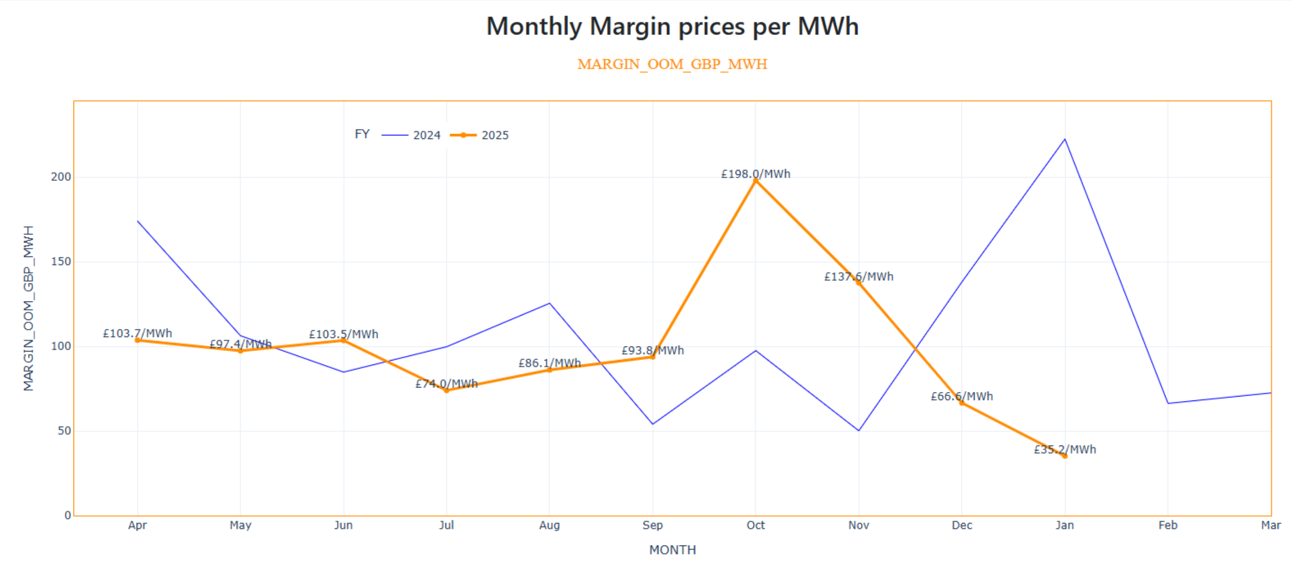
Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£0.7m Reactive costs have decreased slightly on last month, due to the higher proportion of synchronous generation in the mix for January.	**-£0.0m** Reactive costs have stayed in line with last year. This likely reflects significantly lower power prices being offset by a significant rise in wind outturn since last January.

We have started a Network Innovation Allowance (NIA) project that will review 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 significantly in January to £35.2/MWh from £66.5/MWh in December, a reduction of over 47%. This trend is the opposite of what we saw last year, with reserve prices rising from £138.1/MWh in December 2024 to £222.6/MWh in January 2025. This is largely down to a reduction in reserve prices compared with January 2025 when a combination of tighter margins, low wind, and limited interconnector capacity created system conditions for monthly margin prices 532% higher than experienced in January 2026.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£5.2m **Fast Reserve: +£5.2m** Despite a decrease in costs, there was a 168GWh increase in the absolute volume of operating reserve to secure the system compared to December.	**Operating Reserve: -£19.8** **Fast Reserve: +£2.8m** Despite a decrease in costs, there was a 658GWh increase in the volume of operating reserve required to secure the system compared to January 2025.

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
+£1.6m Despite a 6 GWh decrease in the absolute volume of actions compared to December, higher average clearing prices for DC, DM, DR services contributed to an overall higher cost in January.	**+£0.8m** The volume of actions taken for response decreased by 20.9GWh compared to January 2025 but were offset by the higher average Dynamic Regulation clearing prices.

Dynamic Services Average Clearing Prices (£/MW): January 2026 vs December 2025

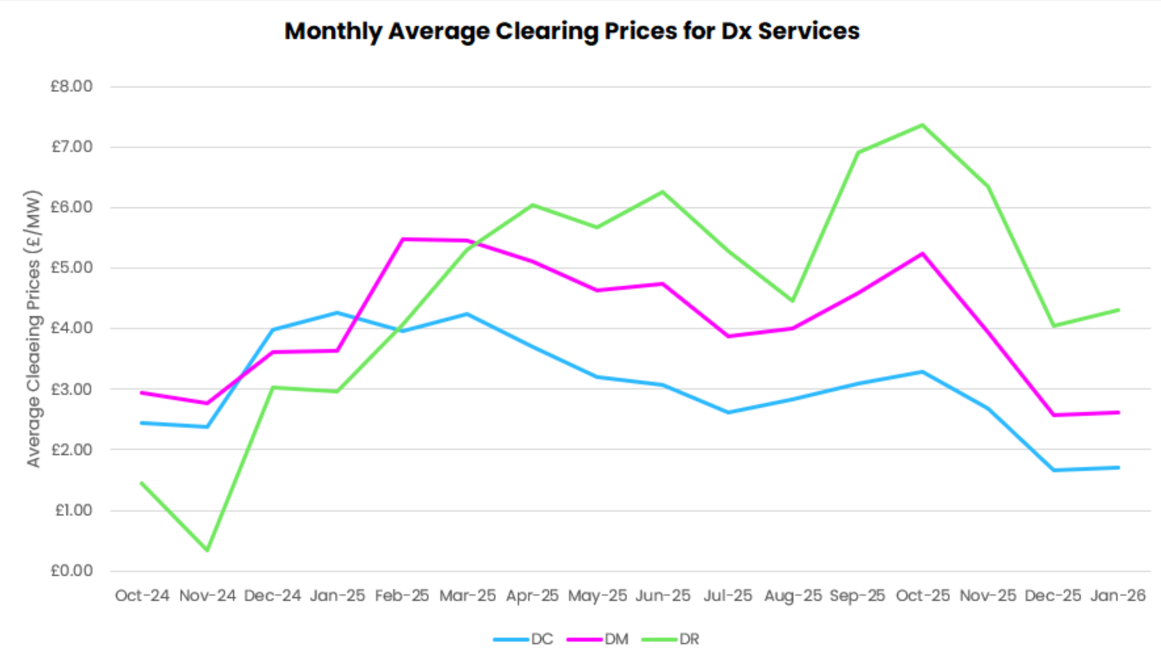
		(a) Jan-26	(b) Dec-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Dynamic Services	DC	1.7	1.7	0.0	
	DM	2.6	2.6	0.0	
	DR	4.3	4.0	0.3	

Dynamic Services Average Clearing Prices (£/MW): January 2026 vs January 2025

		(a) Jan-26	(b) Jan-25	(b) - (a) Variance	decrease ◀▶ increase Variance chart
Dynamic Services	DC	1.7	4.3	(2.6)	
	DM	2.6	3.6	(1.0)	
	DR	4.3	3.0	1.3	

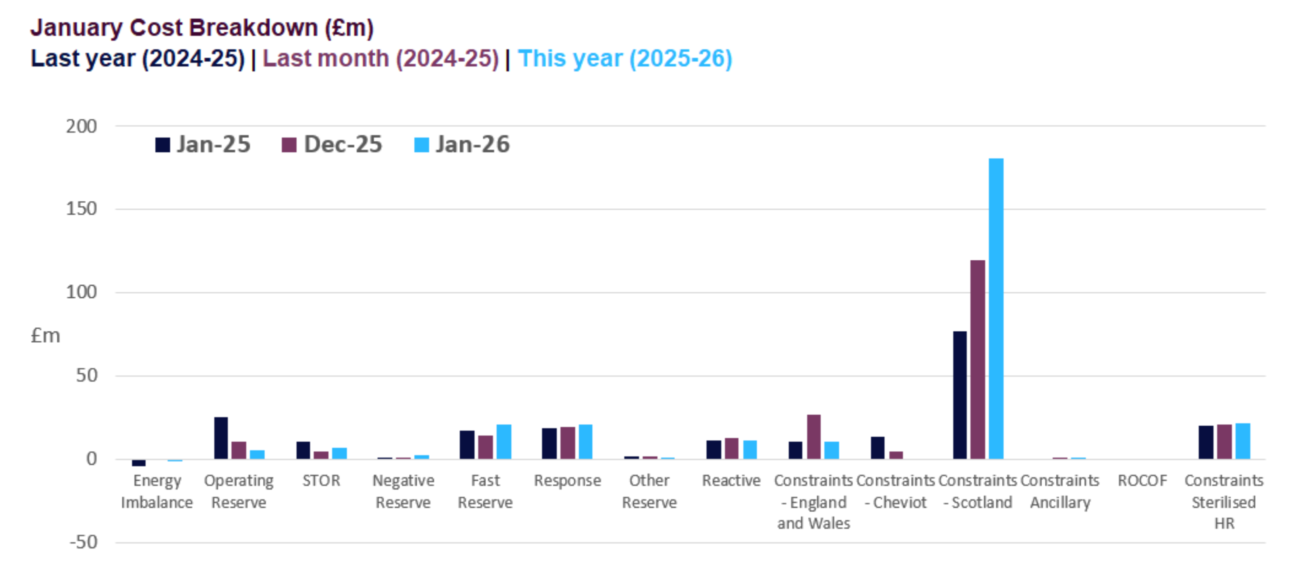
Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM) marginally increased to those observed in December, whilst Dynamic Regulation (DR) also increased, in contrast to the downwards trend that had been seen since October. The increase in Dynamic Regulation prices can be attributed to high wind outturn in January impacting system conditions.

Average clearing prices for Dynamic Regulation have also increased year-on-year, with higher prices being driven by increased procurement requirements for the service since February 2025. Comparatively, Dynamic Moderation and Dynamic Containment average clearing prices have decreased year-on-year, which is due to stable system inertia in January 2026 lowering wholesale price volatility for these services and firm requirements being met most days with ample supply at lower prices.



Comparison breakdown

The graph below shows the breakdown of monthly balancing costs by category compared to the previous month and the same month in the previous year. 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.



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £76m in January 2026. This is a decrease of roughly £33m relative to December 2025 (£109m). The most valuable action was operative measures to offload specific 400kv circuits around London to avoid pre-fault overloads during identified outages. This increased transfer capacities to the east of England by roughly 2950 MW. The cost saving for this action is estimated in £22m.

Cost Savings – Trading

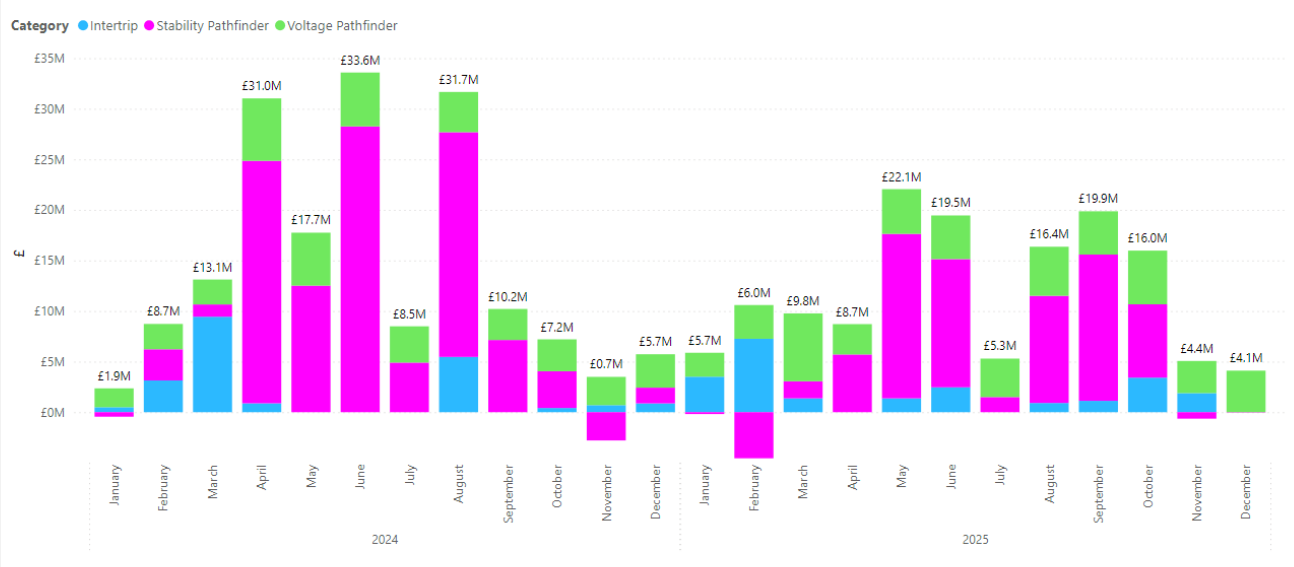
The Trading team were able to make a total saving of £15.2m in January through trading actions as opposed to alternative BM actions, representing a 42% increase on the previous month. This increase has largely come from trading due to margin requirements. In January there were tighter margins over peak times coupled with limited availability in the BM which led to an increased reliance on interconnector trading. The day with the greatest trading savings was on 6 January at a cost of £6.5m with the greatest component being for margin. The day with the greatest spend on trades was also the 6 January at a cost of £13.5m, 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&2 have delivered approximately £116.2 m in savings across 2025/26 to date (April – December 2025).

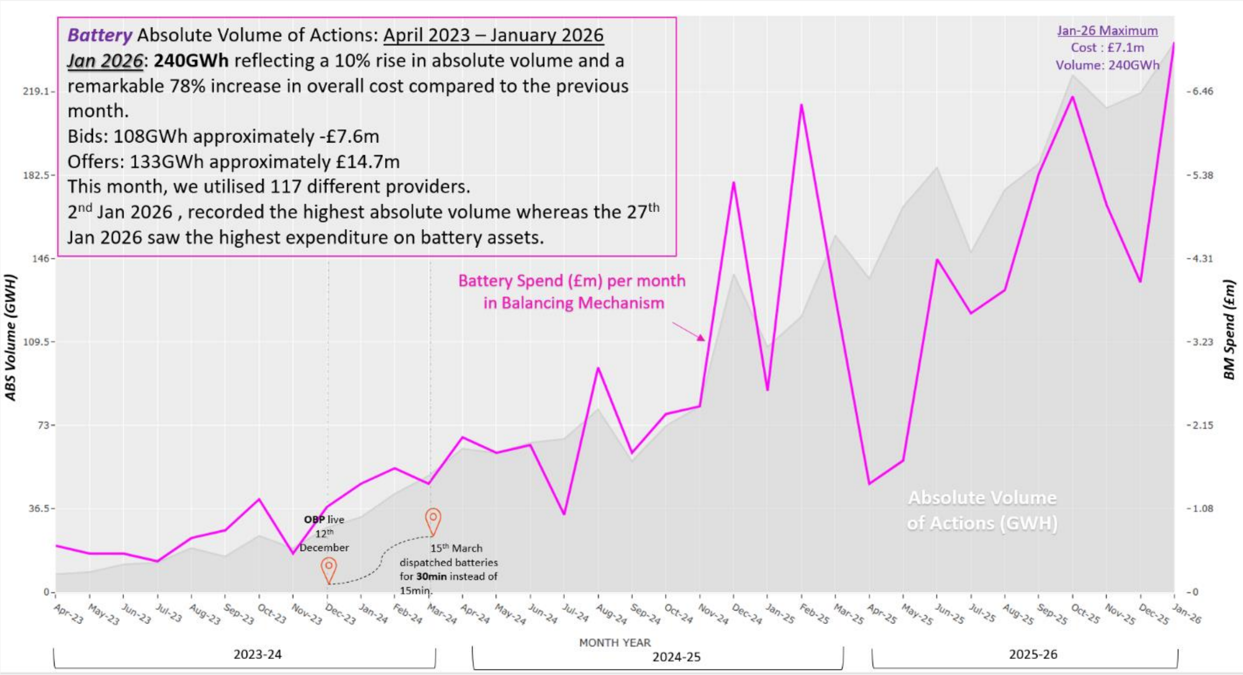
Monthly Savings from Network Services (NS)



NOTABLE EVENTS

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

January 2026



This graph illustrates a clear upward trend in both cost and volume over the observed period from April 2023 through January 2026. 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.

Relative to the month before, January 2026 experienced growth in absolute volume alongside a significant escalation in overall cost.

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

January's balancing costs were £302.7m which was £61m higher than the previous month. This included four days with a total cost above £15m (1, 6, 11, 12), as well as a further 12 days in January having a cost over £10m (2, 14, 21-30). The daily average cost increased from £7.8m to £9.8m, an increase of £2.0m.

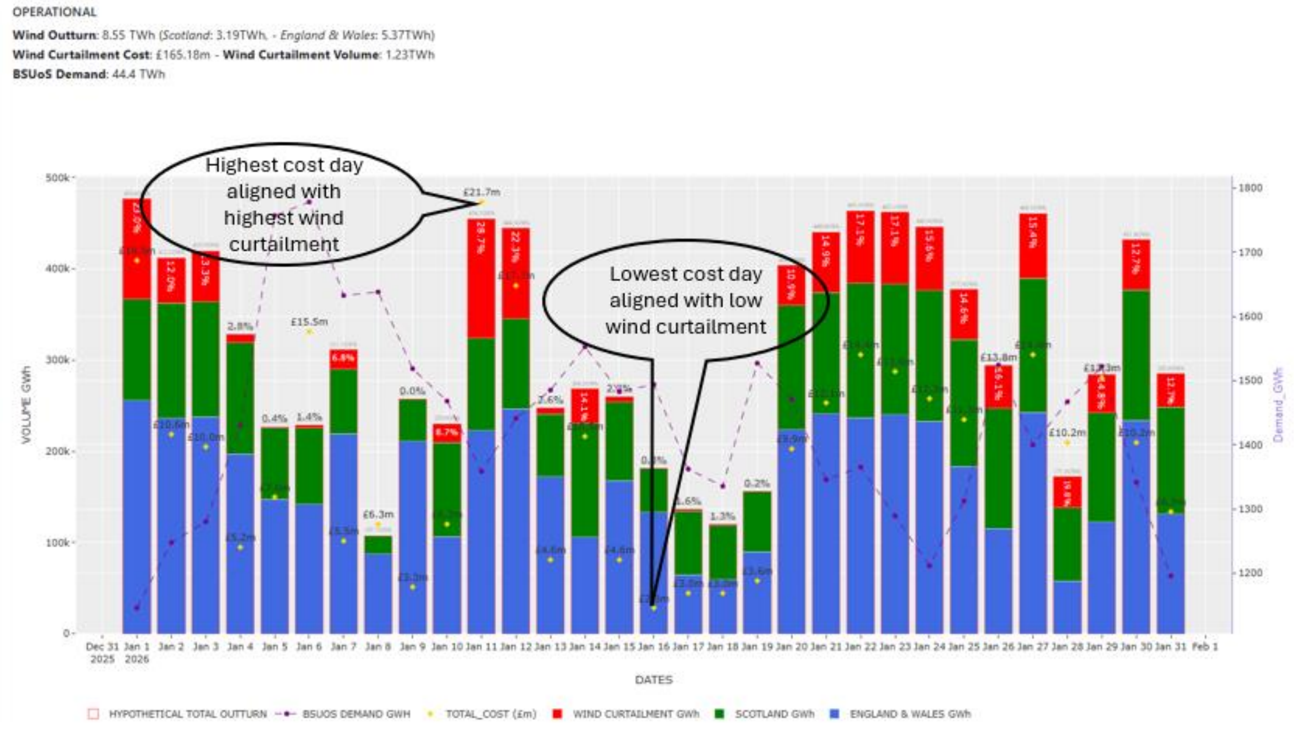
The highest cost day was Sunday 11 January, with a total cost of approximately £21.7m, slightly higher than the highest cost day in December. These costs were driven by the highest level of wind curtailment seen during the month, along with outages on the day.

The lowest cost day was Friday 16 January with a total cost of approximately £2.3m, followed by 17 January at a cost of £2.9m. The 16th had a very low volume of wind curtailment (0.5GWh) while the 17th also experienced low curtailment volumes (2.2GWh). Several returns from outages also took place on the 16 while both days had a low absolute volume of actions taken.

January 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).

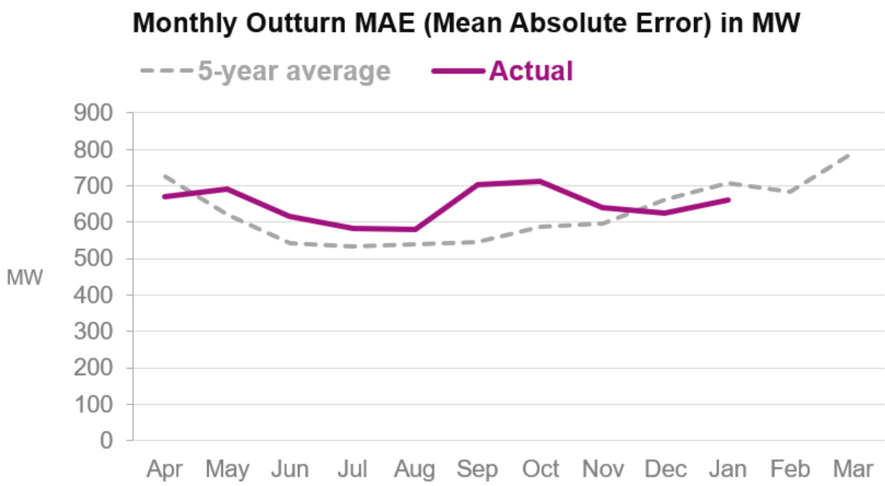
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

January 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**	**626**	**662**		

*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 January 2026 forecasting error averaged 662MW, against the previous 5-year average of 707MW. YTD performance is currently 648MW, vs 5-year average of 606MW.

January brought a very cold start to the year, with frosts and snow across many parts of UK, especially Scotland. Temperatures warmed for the second half of the month, with continued rain and unsettled conditions.

Storm Goretti (8-9 Jan), Storm Ingrid (23-24 Jan) and Storm Chandra (26-27 Jan) brought rain and strong gusting winds to the Southwest. During the worst of Storm Goretti, it was reported that "Tens of thousands of properties lost power", although there is no established link to the over-forecast values during this period.

Return-to-work patterns following the end of the Christmas holiday period, adds further challenges to forecasting.

The largest absolute demand error this month was 2.9GW on 8 January, SP32.

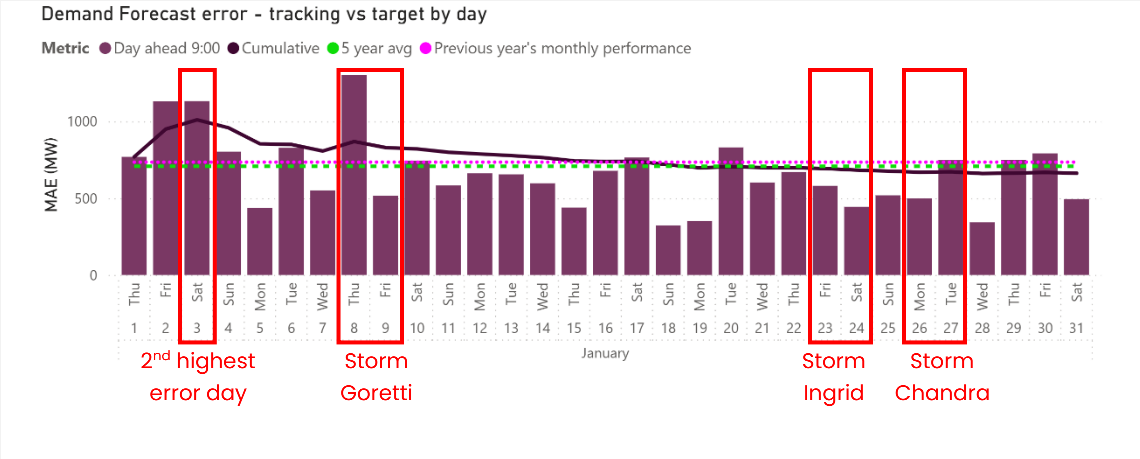
The minimum demand was 20.8GW on 25 January, SP11. The maximum demand was 47.3GW on 5 January, SP35 which is likely to remain the Winter Peak demand for this season.

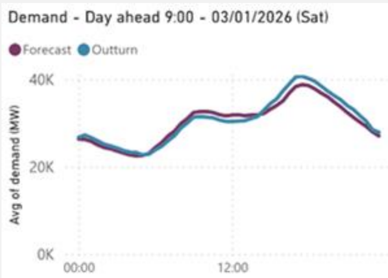
Solar generation peaked at 7.3GW on 5 January.

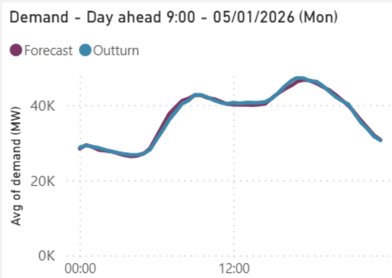
Work continues on rebuilding our national demand forecast models. These will adopt Machine Learning/AI technology and will make use of the latest generation weather data, with an expected release to production in Q1 2026.

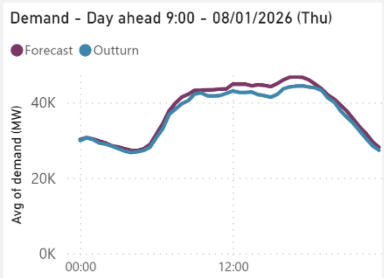
Work continues on our solar forecast upgrades. These will make use of blended-weather (solar irradiance) and blended-forecasts (MW) and we aim to release to production in Q2 2026.

Days of Interest:

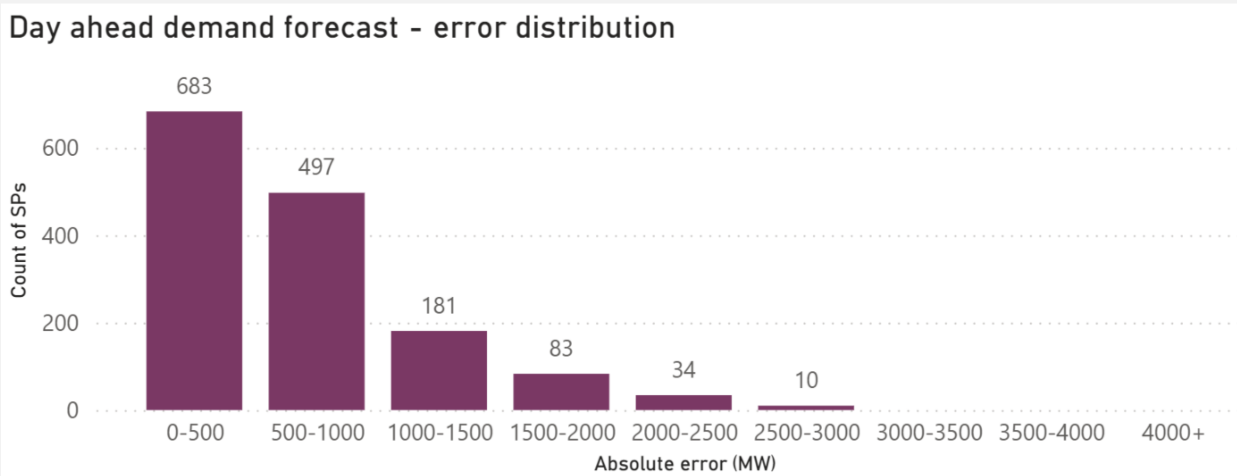




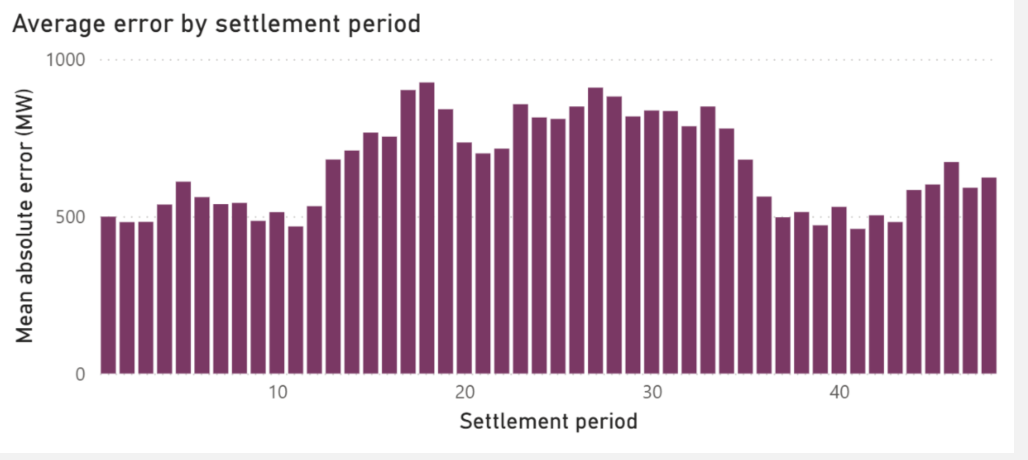




The distribution of settlement periods by error size is shown below:



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



The days with largest MAE were 2, 3 and 8 January.

Day	Error (MAE)	Major causal factors
2	1129	Forecast errors likely due to human behaviour changes returning from holiday period, and solar forecast error in the middle of the day
3	1132	Forecast errors likely due to human behaviour changes returning from holiday period, and solar forecast error in the middle of the day
8	1300	Over forecast across the whole day, with larger wind errors in the second half of the day

Missed / late publications

There were no late or missed publications in January.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 5, 6, 8, 14, 16, 19, 20, 26, 28, 29 and 30 January, with an accumulated total of 860MWh 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.

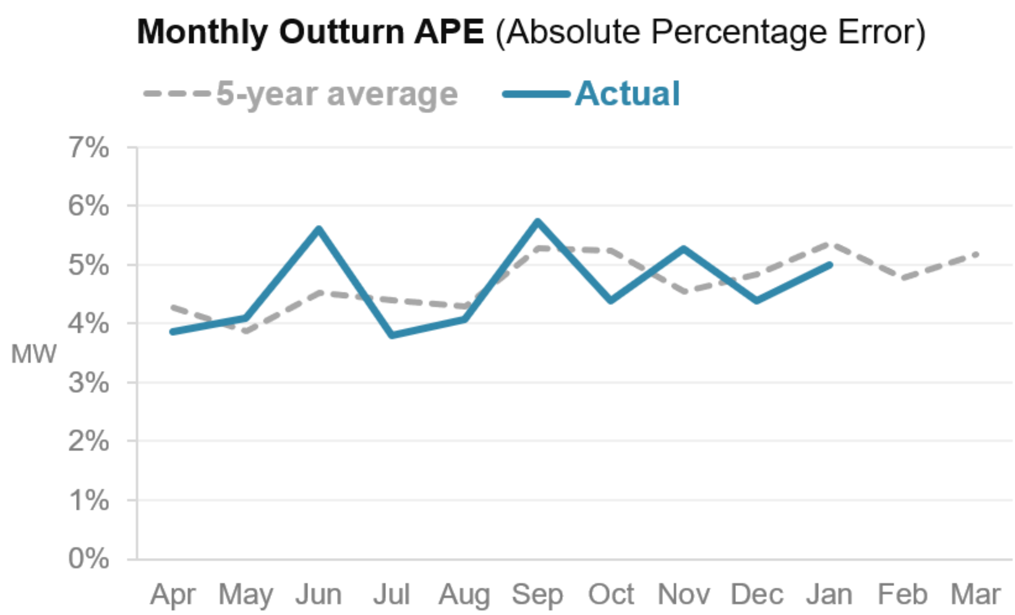
Sites deemed to have withdrawn availability are those that:

- 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.

January 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 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**	**4.06**	**5.74**	**4.38**	**5.27**	**4.39**	**4.99**		

*Ofgem 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 January 2026, BMU wind forecasting error averaged 4.99%, against the 5-year average of 5.36%. YTD performance is currently 4.62%, vs 5-year average of 4.66%.

In January, storms Goretti, Ingrid and Chandra brought strong gusting winds, especially over the southwest. Peak wind gusts of 99mph were recorded. The second half of the month contained more unsettled weather, low pressures a constant presence to the west/southwest of the UK.

Numerous days, including some outside of the named-storm periods, experienced high speed shutdown occurrences, but these were accounted for in the forecasts.

An IT issue with NESO ingestion-pipelines was the root cause of the large error on 28 Jan., as updated weather forecasts (27 Jan) were not able to be processed.

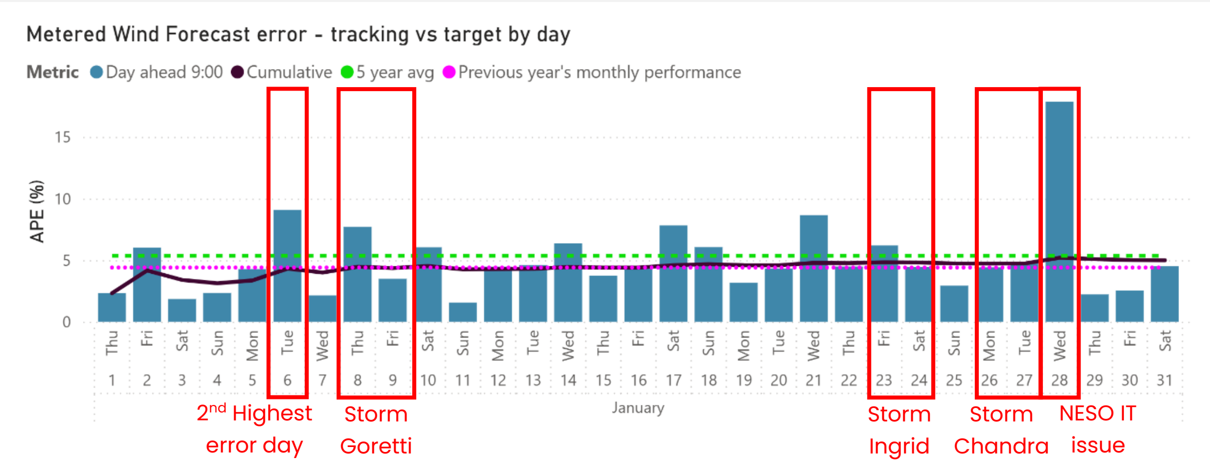
Metric-adjusted wind generation peaked at 16.5GW on 24 January, SP41.

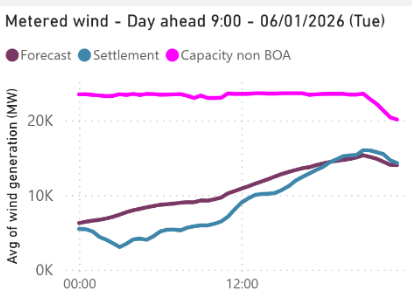
Wind forecast absolute error peaked at 4.7GW on 28 January, SP44.

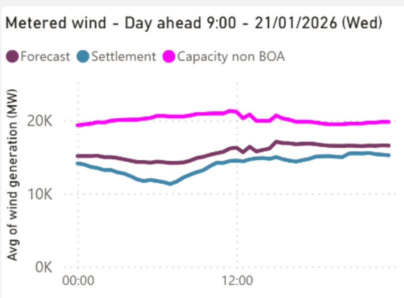
Work continues on our wind generation forecast model upgrades and we have now released the blended-weather (windspeed) feature. Work continues on the wind-direction feature and we aim to release to production in Q1 2026. From Q2, we intend to focus on enhancing our within-day capability.

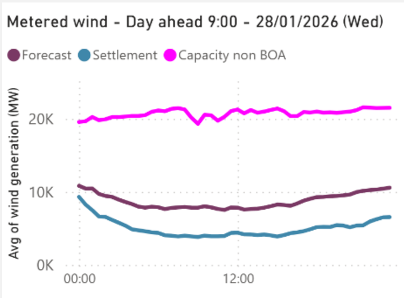
Metric values for previous months have been recalculated with updated settlement outturns and these are reflected in the YTD performance.

Days of Interest:

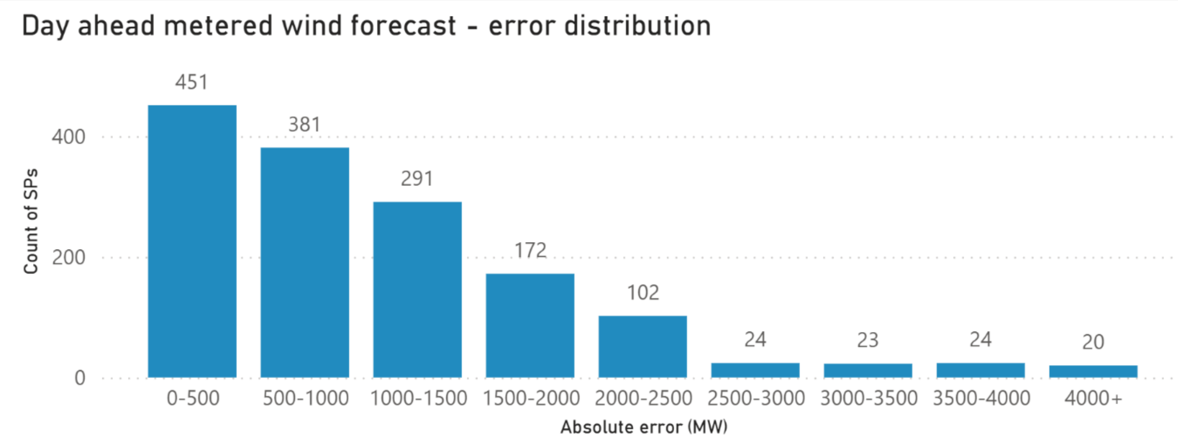








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
6	9.1	Wind speed forecast errors at day-ahead stage
21	8.7	Wind speed forecast errors at day-ahead stage
28	17.9	Weather data ingestion delayed due to NESO IT issue, now resolved

Missed / late publications

There were no missed or late publications in January.

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

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Offers	43%	35%	33%	36%	31%	32%	30%	33%	29%	28%		
Bids	43%	42%	47%	46%	39%	42%	40%	35%	37%	40%		
Combined	**42%**	**39%**	**38%**	**42%**	**35%**	**36%**	**34%**	**34%**	**32%**	**31%**		

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	113	144		
Offers – in merit Energy volume	148	205	356	215	279	359	437	309	392	516		
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971	1084	878	838	827		
Bids – Skipped volume	141	148	111	127	122	102	93	108	103	80		
Bids – in merit Energy volume	336	352	234	277	316	243	234	310	280	200		
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488	1815	1597	1660	1921		
Combined Bid & Offer – skipped volume	204	219	227	205	208	218	226	211	216	224		

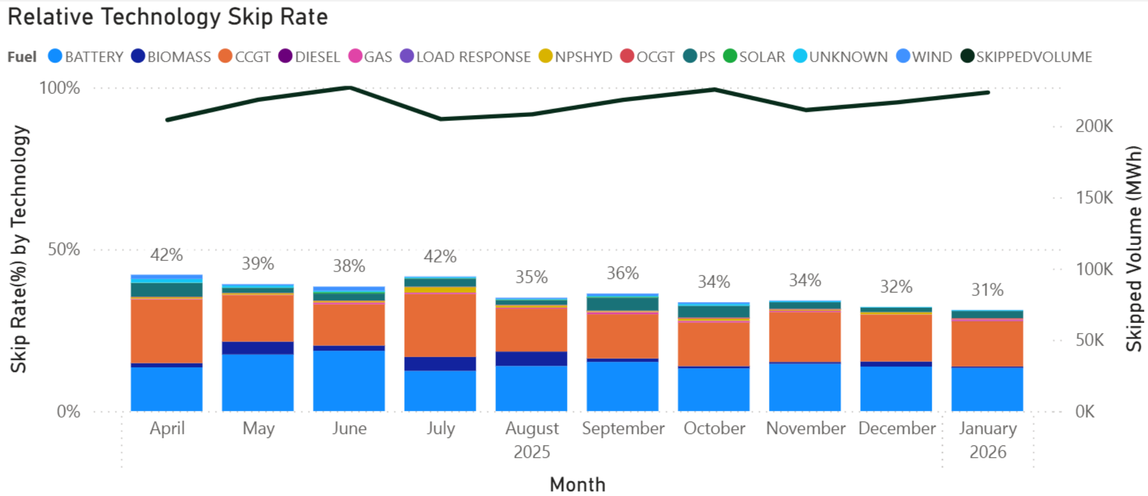
Supporting information

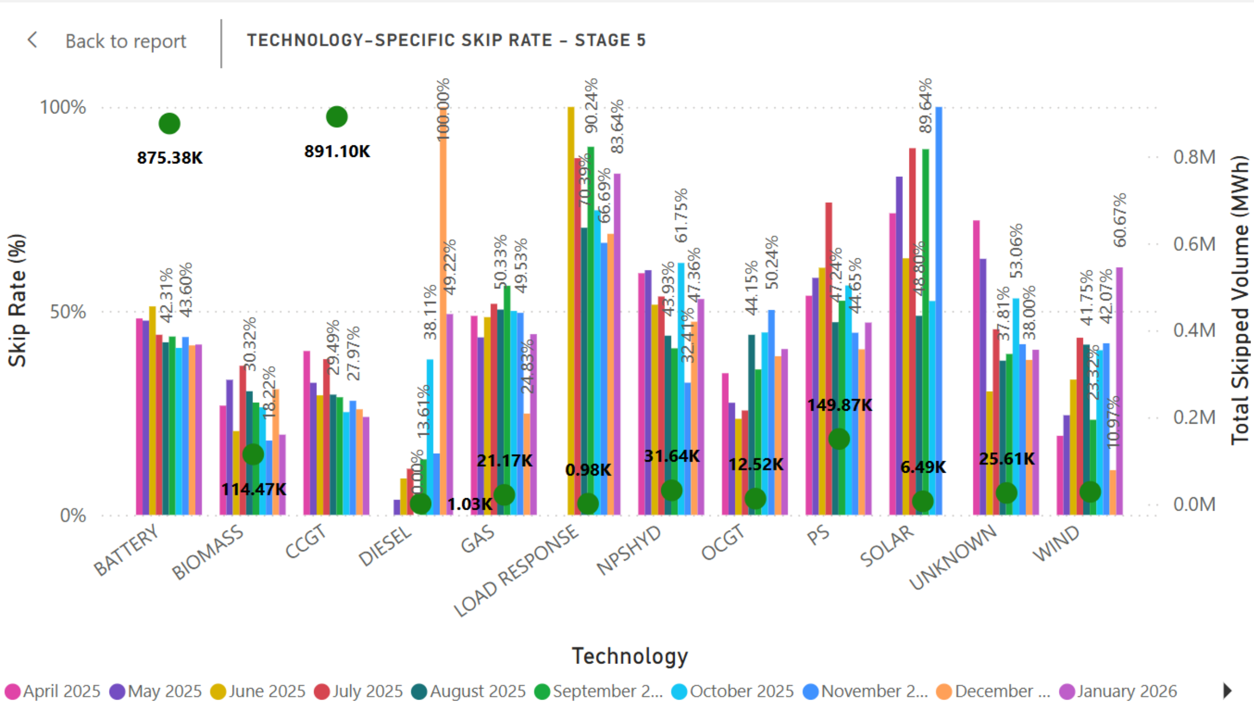
JANUARY UPDATES

We hosted the Dispatch Transparency Forum on 28 January in London and 57 people from industry attended it. We presented updates on materiality, skips behind constraints and the target. The industry was positive and convinced with our approach during the event. Final details for the skips behind constraint method are being developed in alignment with ENCC and planning for implementation is underway.

JANUARY PERFORMANCE – COMBINED BIDS AND OFFERS

The combined bid and offer skip rate continued to trend downwards during 2025 and was significantly lower in January 2026 (31%) than January 2025 (43%). The combined skip rate decreased in January to the lowest level seen to date.



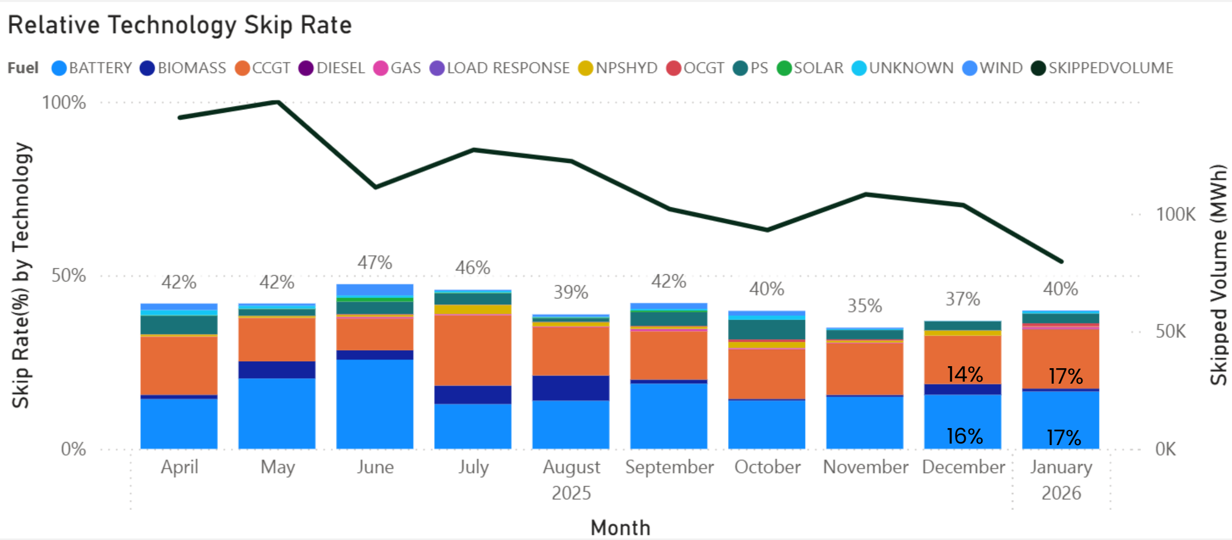


The combined technology specific skip rate has continued to trend down for most technology types since April 2025. This includes Batteries and CCGTs which account for most of the skipped volume. Some technology types see very high or low technology specific skip rates when they have small in merit volumes. For example, in January load response units were in merit for 132 MWh and skipped for 110MWh resulting in 84% technology specific skip rate. Similarly solar has a 100% technology specific skip rate in November – this was 30MWh of skipped volume over a 2-hour period on one day.

Note: In the technology specific skip rate graph '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. We have published a dedicated dataset to report skip rates for DSF units and incorporated this into our external dashboard. A summary is provided below.

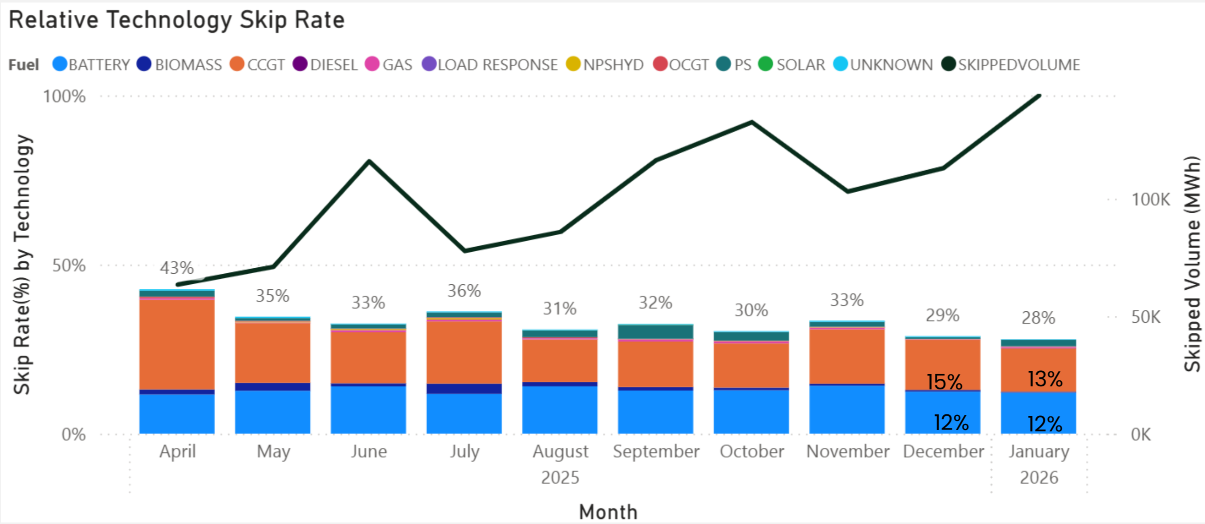
Bids

The Bid skip rate has increased from December (37%) to January (40%), and the skipped volume has decreased from 104GWh to 80GWh. CCGTs accounted for a higher proportion of skipped volume in January (17%) compared to December (14%) and the Technology Specific skip rate for CCGTs have remained consistent at 31%. Batteries account for a higher proportion of the skip rate in January (17%) compared to December (16%) and the Technology Specific skip rate has increased from 42% to 47%. This has primarily been driven by disproportionately small reduction in skipped volume (44GWh to 33GWh), compared to a bigger drop in in-merit volume (105GWh to 70GWh).



Offers

The Offer skip rate decreased in January (28%) from December (29%). CCGTs account for a lower proportion of skipped volume in January (13%) than December (15%), and the Technology Specific skip rate has decreased from 23% in December to 21% in January. Batteries account for same skipped volume in December (12%) and January (12%), and the Technology Specific skip rate has decreased from 41% in November to 39% in December.


Relative Technology Skip Rate
Fuel BATTERY BIOMASS CCGT DIESEL GAS LOAD RESPONSE NPSHYD OCGT PS SOLAR UNKNOWN SKIPPEDVOLUME
100%
50%
0%
Skip Rate(%) by Technology
100K
50K
0K
Skipped Volume (MWh)
43%
35%
33%
36%
31%
32%
30%
33%
29%
28%
15%
12%
13%
12%
April
May
June
July
August
2025
September
October
November
December
January
2026
Month

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).

his 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.

January 2025-26 performance

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

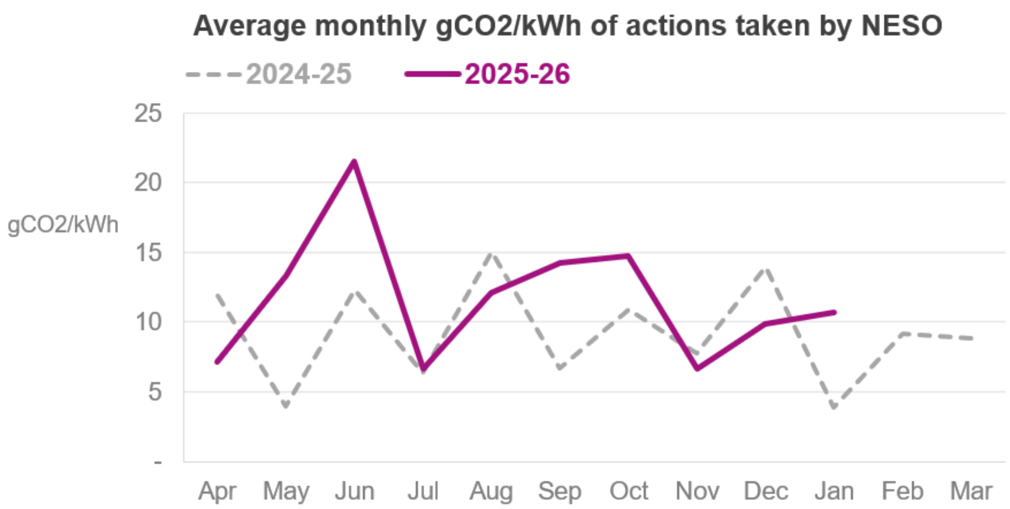


Table: Average monthly gCO2/kWh of actions taken by NESO

	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	9.85	10.71		

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 could see biomass and CHP units treated differently in this report, but no change has been made as yet.

In January the average monthly carbon intensity from NESO actions was 10.71g/CO_2/kWh. This is 0.86g/CO_2/kWh higher than December, and 0.99g/CO_2/kWh lower than the YTD average of 11.70/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 58.96g/CO_2/kWh which took place on 1 January at 00:30. This is 5.94g/CO_2/kWh lower than the highest point in December of 64.90g/CO_2/kWh.

On 1 January constraints were active due to high levels of wind and weather warnings across the UK.

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.

January 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	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	0	0		
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	1	0	0	1	0	0	0	0		

Supporting information

No reportable voltage or frequency excursions during January.

[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.

January 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	0	0		
Integrated Energy Management System (IEMS)	0	0	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	0	1 outage 120 mins		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0		

Supporting information

In January 2026 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 15 January, 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 January.

There were no unplanned outages during January.

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