25 November 2025

Monthly Incentives October 2025 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 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 October 2025:

Reported Metric		Performance
1	**Balancing Costs**	**£326m**
2	**Demand Forecasting**	Forecasting error of **711MW**
3	**Wind Generation Forecasting**	Forecasting error of **4.33%**
4	**Skip Rates**	Post System Action (PSA) Offers: **30%** Bids: **45%** Combined: **36%**
5	**Carbon intensity of NESO actions**	**14.75 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**	**0** 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.

October 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

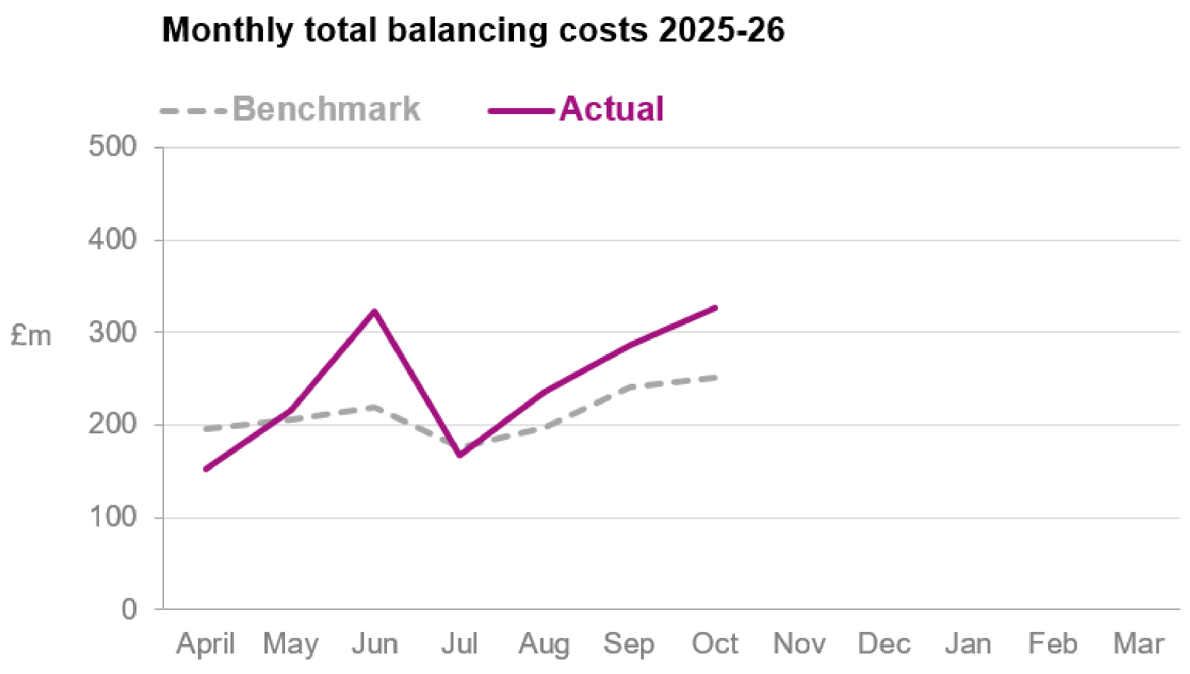


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

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						34.9
Average Day Ahead Baseload (£/MWh)	81	77	73	80	73	72	77						n/a
Benchmark*	195	206	219	176	197	241	251						1486
Outturn balancing costs[1]	**152**	**215**	**324**	**167**	**236**	**287**	**326**						**1707**

[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

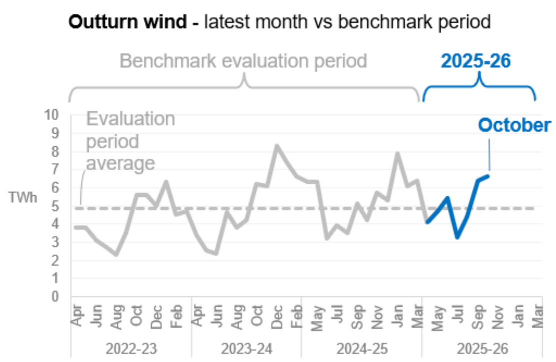
This month's benchmark

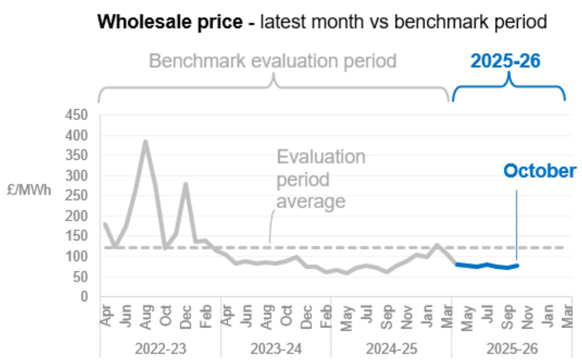
The October's benchmark of £251m is £10m higher than September 2025 and reflects:

An outturn wind figure of 6.6 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 September 2025's figure (6.4 TWh).

An average monthly wholesale price (Day Ahead Baseload) has increased compared to September 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 October's benchmark compared to September.





Variable	October 2025	September 2025	October 2024
Average Wholesale Price (£/MWh)	**77**	**-5**	**+11**
Total Wind Outturn (TWh)	**6.6**	**-0.2**	**-0.9**
Benchmark (£m)	**251**	**-10**	**-12**

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

Balancing Costs – Overview

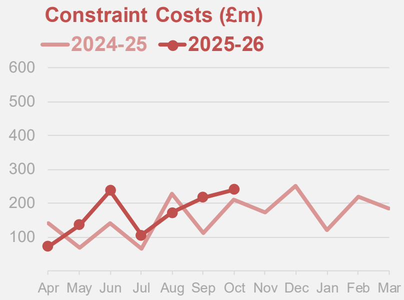
The total balancing cost for October was £326.19m, which is £75.3m (~30%) above the benchmark.

October saw an increase in wind outturn to 6.6TWh compared to September at 6.4TWh. The rise was largely driven by Storm Amy at the beginning of the month, which caused exceptionally high wind output in Scotland. The surge in wind generation also led to a sharp increase in Scottish constraint costs which rose by £52m compared to the previous month. Despite the low wind output near the middle of the month, October has had a higher number of high-cost days. This was due to the combination of storm driven output early in the month, high outturn towards the end and several outages in Scotland all contributing significantly to higher thermal constraint costs.

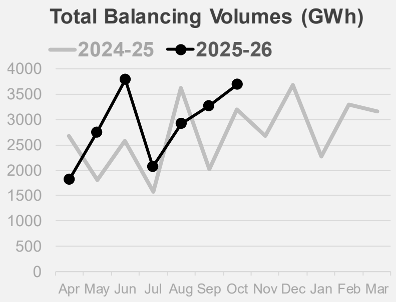
Voltage constraint costs have seen an increase this month due to some units that would have provided reactive support being on outage in the Southwest region. This follows with the drop in stability constraint costs as the two are co-optimised.

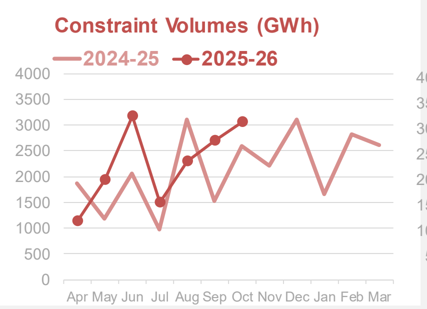
Non constraint costs have increased by £12m partly because of higher priced frequency response and operating reserve required to maintain system stability.

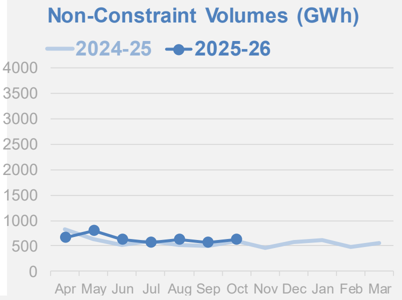
Average wholesale prices increased by £5/MWh from September 2025 likely because of increased domestic demand this month. The volume weighted average (VWA) price of bids was -£21.0/MWh, which is less than September's price which was -£25.2/MWh. This negative bid price reflects that most of the bid actions taken were to curtail wind. The VWA price for offers increased to £127.4/MWh, compared to £121.4/MWh in September, aligning with the rise in wholesale prices.



Absolute Balancing VOLUMES (GWh) monthly vs previous year





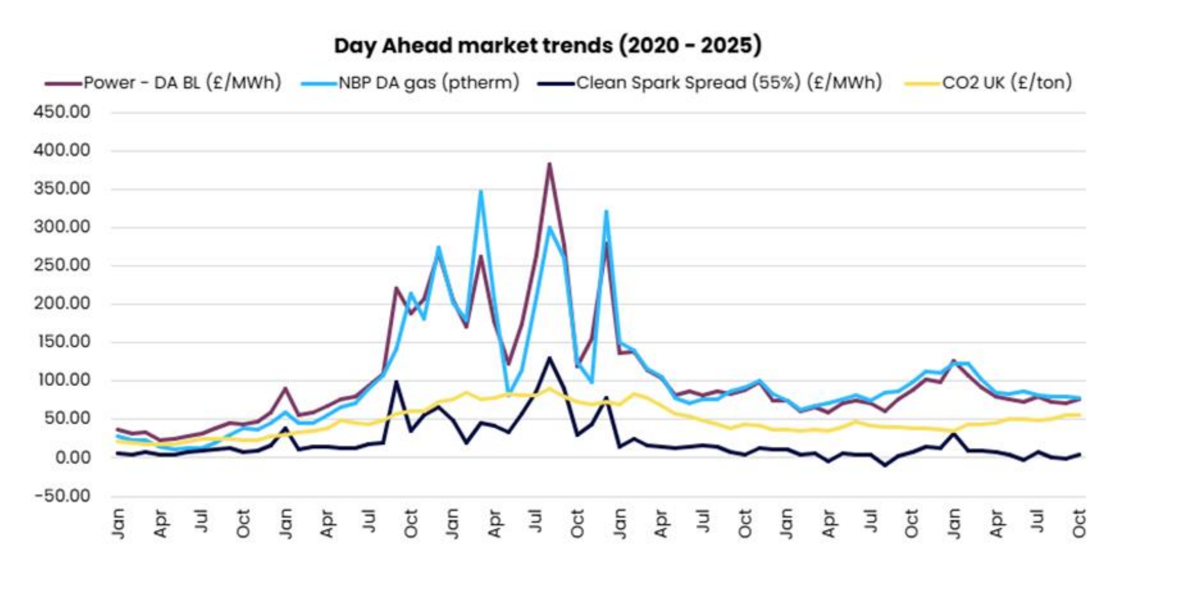


*Please note that the charts above now show <u>absolute volume</u> rather than net volume.

System and Market Conditions

Market trends

In October, gas prices and CO_2 dropped marginally to 78.29p/therm and £55.68/ton however power prices rose sharply to £77.32/MWh. The month was shaped by seasonal temperature shifts as we continue to move further in autumn and variable wind conditions. We have had unseasonably low wind output in the middle of the month and an increase in domestic demand as temperatures have dropped. This has increased the reliance on gas fired generation exerting an upward pressure on gas prices. We have also seen a rise in nuclear generation this month which has contributed to the rise in power prices and an increase in the clean spark spread.



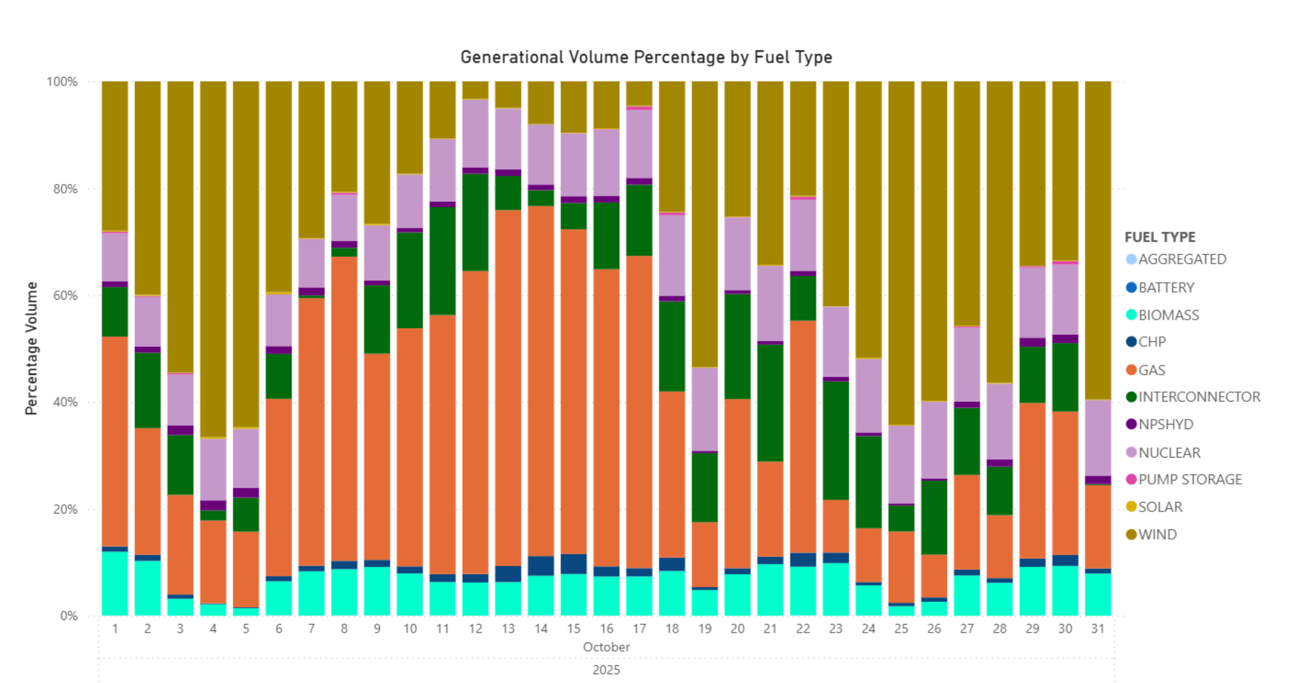
DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Generation Mix

In October, wind was the largest contributor to electricity generation, making up 30% of the total mix. This was followed by CCGTs at 26% and Nuclear at 12%. The pattern is consistent with September, when wind and CCGTs also held the top two positions in the generation mix.

The chart shows that wind generation was particularly strong during the first and last weeks of the month. On the 4th, 5th, 25th, and 26th, wind accounted for around 60% or more of daily generation.

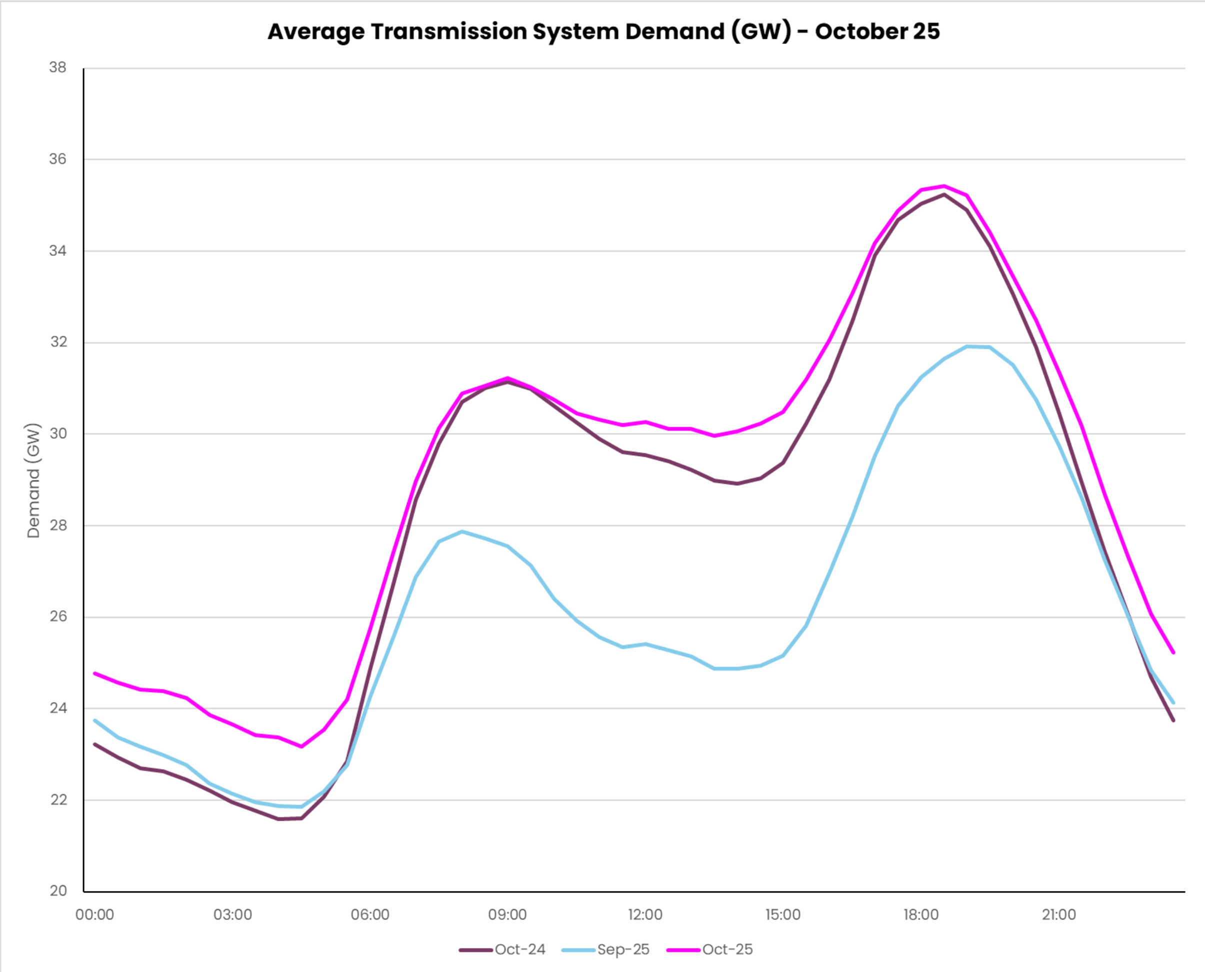
In contrast, wind output dropped significantly in the middle of the month, ranging between 3-30% across several days. Compared to September, October had more days with low wind generation, which led to increased reliance on gas, while slightly reducing the need for other fuel sources.



*Generation mix includes exports from interconnectors.

Transmission System Demand

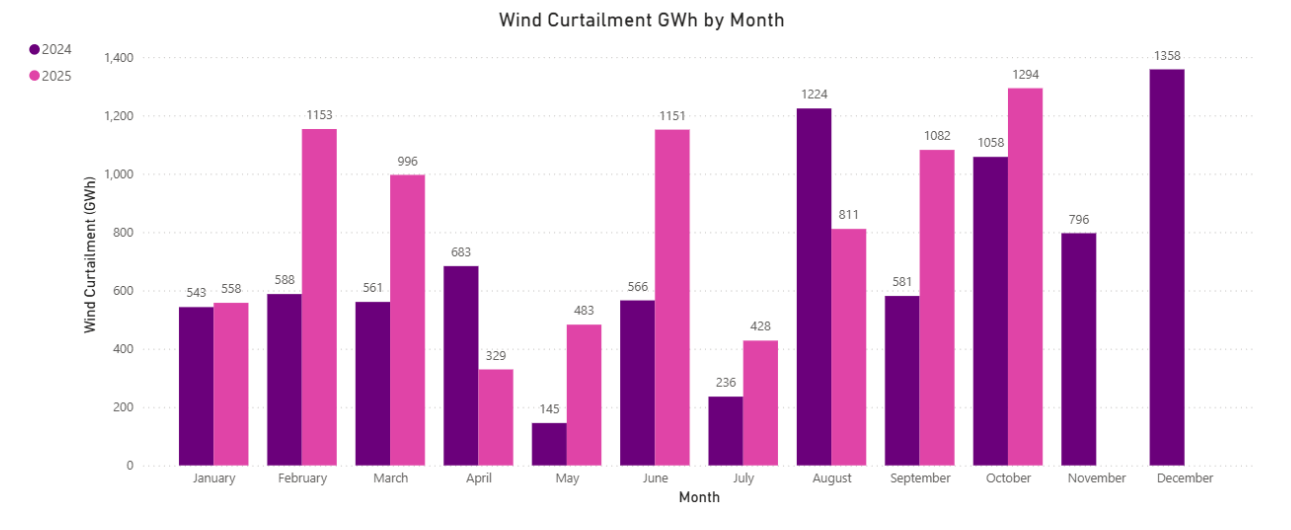
In October the average Transmission System Demand (TSD) was higher than September throughout the whole day, which can be expected due to increased hours of darkness, colder weather, the effects of clock change later in the month, and lower levels of embedded solar generation during the daytime. Comparing October 2025 to October 2024, the average TSD was notably higher during the early morning and afternoon, with the average TSD reaching up to 1.7GW higher than the previous year during the hours of 01:00-02:00, and up to 1.2GW between 14:30-15:00. This trend of difference is likely due to October 2025 being generally colder and darker than October 2024, with a recorded 63.3 hours of sunshine providing just 69% of the monthly average, which has the effect of driving up demand. October 2025 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.



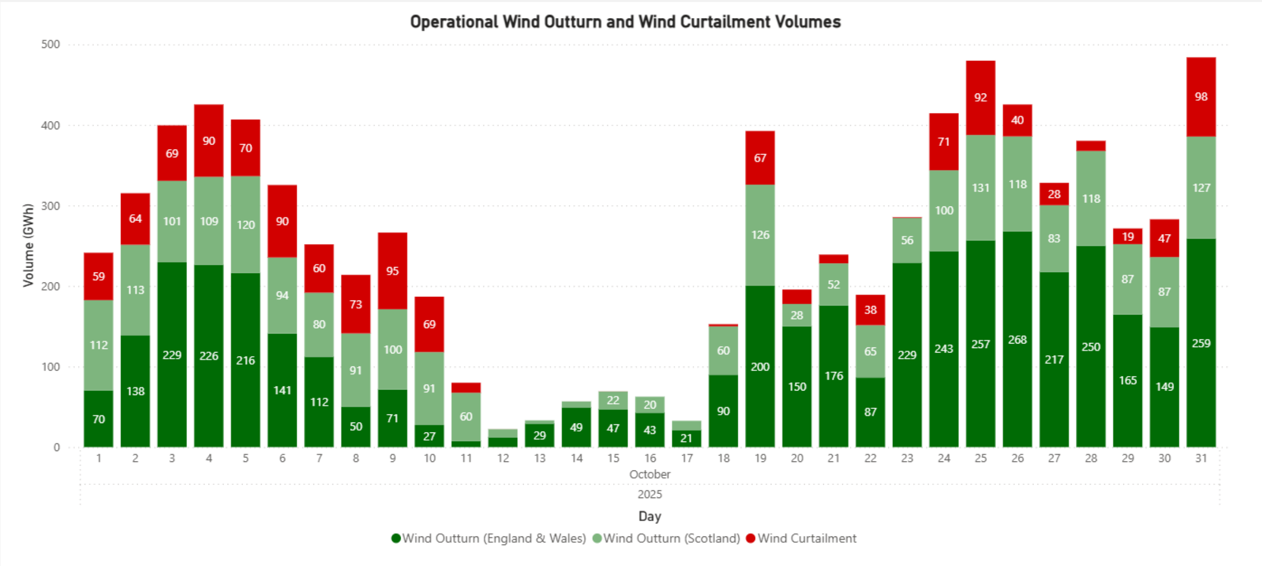
Wind Outturn

Early October wind outturn was heavily influenced by the gale force winds brought about by Storm Amy, which hit the UK on 3 October. The storm brought around 50-75mm of rainfall in some areas. By the second week of the month the rain had eased and high-pressure brought 'anti-cyclonic gloom' – settled conditions with cloud; it was the UK's third dullest October on record.

Overall wind outturn rose from 6.4 TWh in September to 6.6 TWh in October, with a 2.4% increase in England & Wales (from 4.13 TWh to 4.23TWh) and a 6.3% increase in Scotland (from 2.24 TWh to 2.38 TWh) compared to the previous month, giving a 3.1% increase overall. There was also an associated 19.6% increase in the volume of wind curtailment seen since last month. In addition to a 0.9 TWh (16%) increase in overall wind outturn compared to October 2024, there was also a significant 22% increase in the volume of wind curtailment in October 2025 compared to October 2024 (from 1,058GWh to 1,294GWh). With variable weather conditions throughout the month, the highest volume wind curtailment days were spread throughout the month; on 9 October (95GWh), 25 October (92GWh), and 31 October (98GWh).



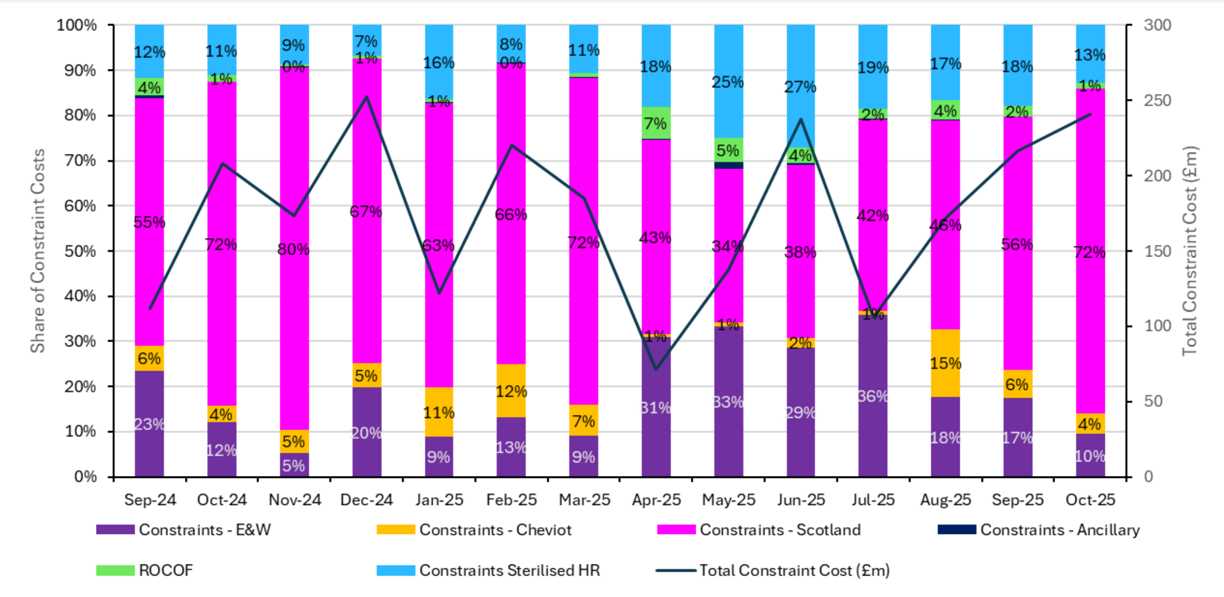
The day with the highest volume of wind curtailment occurred on Friday 31 October with 98 GWh. There was a total wind outturn of 484 GWh on this date, the highest outturn this month. This was also the overall second highest-costing day in October.



Constraints

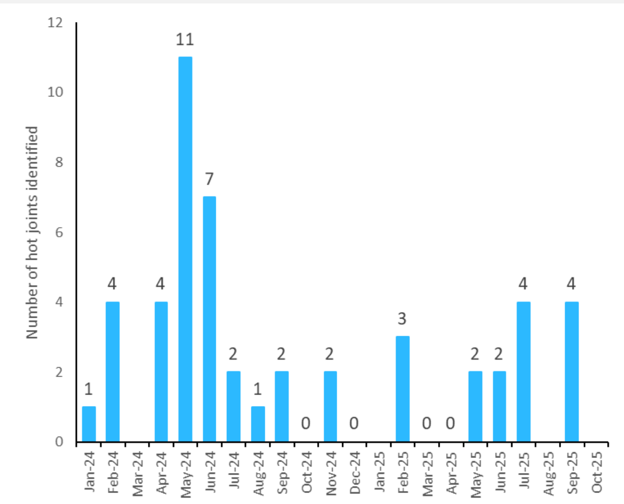
Constraint costs increased from £216.6m in September to £240.9m in October, an increase of £24.3m. This increase was mainly due to an increase in Scottish constraint costs (from £121.7m to £173.4m), while constraint costs decreased in England & Wales and the Cheviot region by 39.5% and 19% respectively.

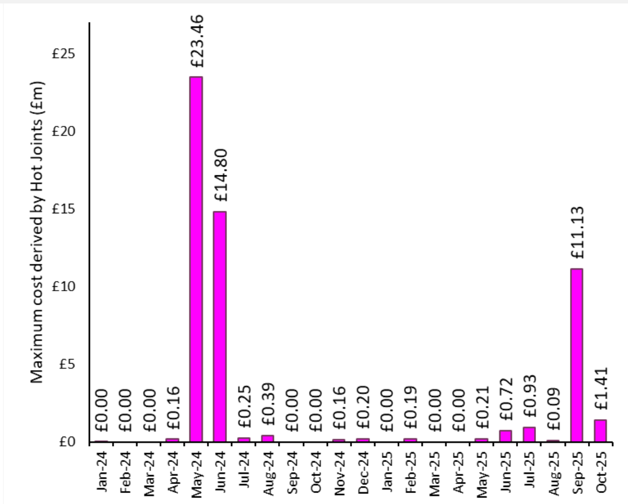
Wind levels across England & Wales and Scotland increased in October. This led to a notable rise in wind curtailment volumes compared to September, driven largely by several periods of unsettled weather (including that brought about by Storm Amy early in the month).



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 September, three hot joints were identified near Bolney and Lovedean, and an additional one was reported near Bramford. The estimated maximum cost to the system for these hot joints was approximately £11 million in September, which decreased after they were resolved.





BALANCING COSTS DETAILED BREAKDOWN

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

		(a) Sep-25	(b) Oct-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-1.1	0.7	1.9	
	Operating Reserve	9.6	13.5	3.9	
	STOR	7.6	8.3	0.7	
	Negative Reserve	0.6	1.6	1.0	
	Fast Reserve	13.8	15.5	1.7	
	Response	23.2	23.5	0.3	
	Other Reserve	1.3	1.3	(0.1)	
	Reactive	11.0	13.2	2.1	
	Restoration	7.3	6.1	(1.2)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	0.0	1.6	1.6	
Constraint Costs	Constraints - E&W	37.9	22.9	(15.0)	
	Constraints - Cheviot	13.2	10.7	(2.5)	
	Constraints - Scotland	121.7	173.4	51.8	
	Constraints - Ancillary	0.1	0.2	0.0	
	ROCOF	5.0	3.0	(2.1)	
	Constraints Sterilised HR	38.7	30.7	(7.9)	
Totals	Non-Constraint Costs - TOTAL	73.3	85.3	12.0	
	Constraint Costs - TOTAL	216.6	240.9	24.3	
	Total Balancing Costs	**289.9**	**326.2**	**36.3**	

As shown in the totals from the table above, constraint costs increased by £24.3m and non-constraint costs increased by £12m which results in an overall increase in costs of £36.3m compared to September 2025.

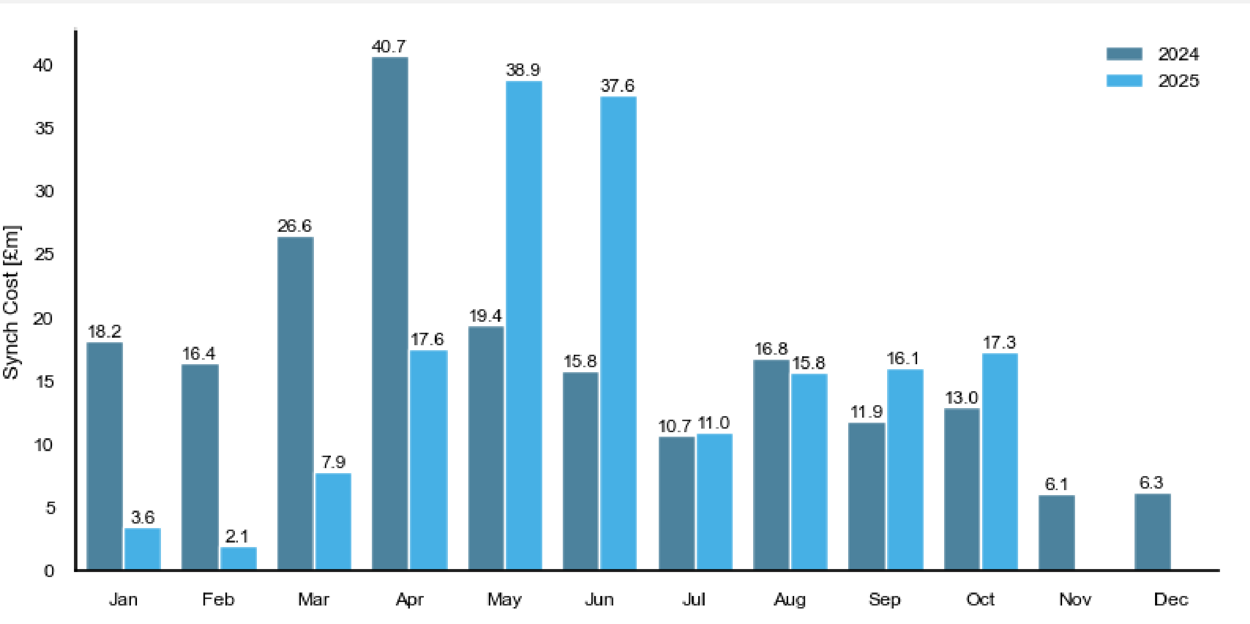
Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: +£49.3m **Constraint – England & Wales: -£15m** **Constraint Sterilised Headroom: -£7.9m** Overall constraint costs increased in October by £24.3m, which coincided with an increase in the absolute volume of actions taken. This was partly due to an increase in wind output, which reached 6.6 TWh in October, compared to 6.4 TWh in September. The higher wind levels led to a rise in thermal constraint costs across GB, particularly in Scotland where a large proportion of system outages have been	**Constraints – Scotland & Cheviot: +£32.1m** **Constraints – England & Wales: -£2.4m** **Constraints Sterilised Headroom: +£4.4m** Constraint costs across GB have increased by £31.1million compared to October 2024, largely driven by a significant rise in wind output and the resulting curtailment and balancing actions. Of note is the increase in Scotland & Cheviot, indicating that constraints were more concentrated in the northern part of the country this year.

located in October, restricting boundary capacity. **ROCOF: -£2.1m** 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.	**ROCOF: +£0.1m** There was a slight increase in inertia spend compared to October 2024. This increase will be in part due to the higher levels of overnight wind displacing synchronous generation, which then has to be dispatched in the BM to access required inertia.

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 October, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) were £17.3m. This represents an increase of approximately £1.2 million compared to September 2025 and is £4.3 million higher than the same period last year (October 2024).

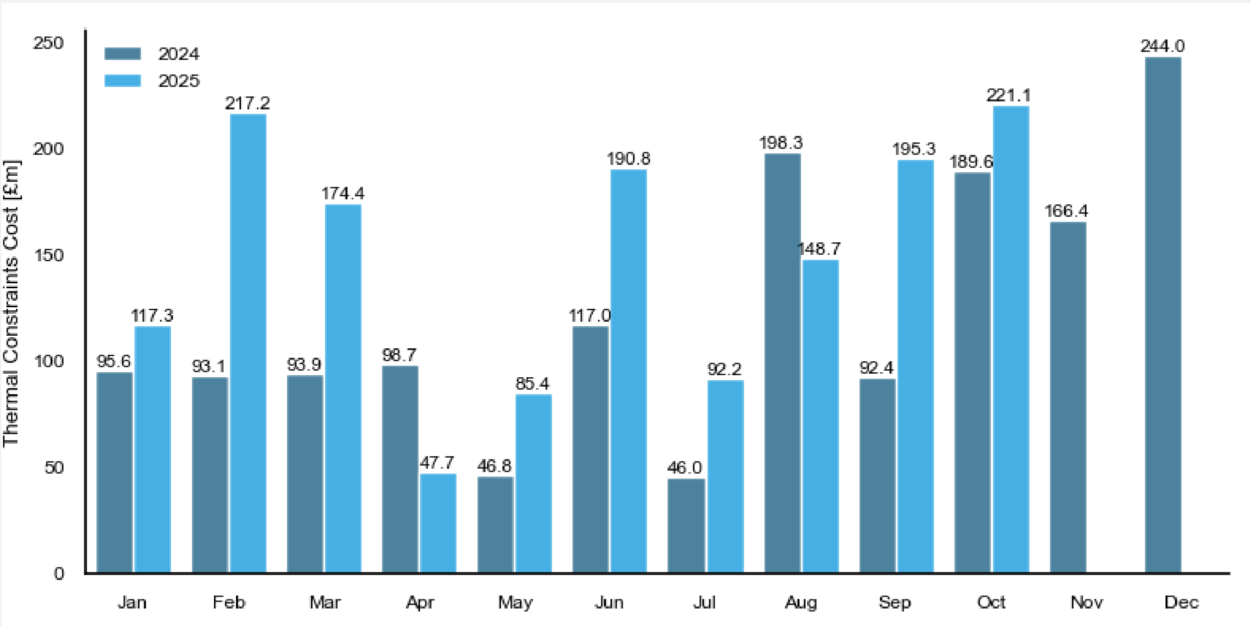


Voltage spending is usually higher overnight: lower demand means that some synchronous units (mostly CCGTs) that usually provide reactive support are not self-dispatched, which forces NESO to procure those services through the Balancing Mechanism.

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:

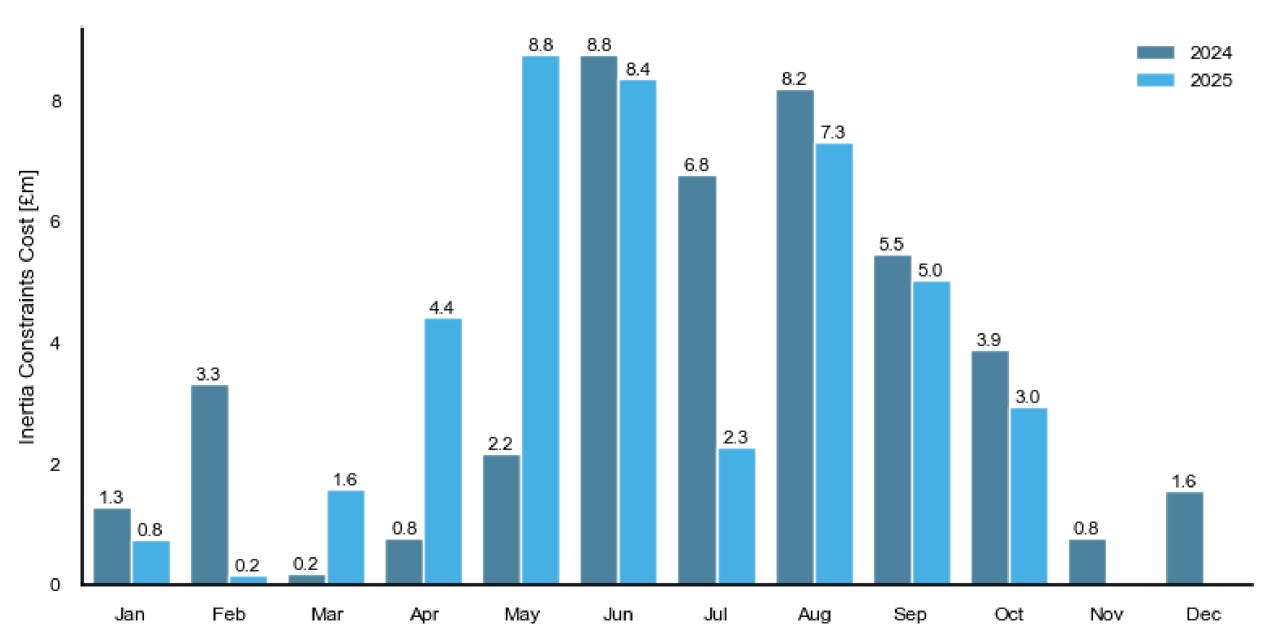
Thermal constraints are linked to operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, often referred to as the B4, B5, and B6 boundaries. The expenditure on thermal constraints 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 October, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £221.1m, reflecting an increase in costs of over £25.8m compared to the previous month (£195.3m). When compared to the same period last year (£189.6m in October 2024), the cost was up by £31.5 million, a notable year-on-year rise.



October 2025 saw a significant increase in wind curtailment, contributing to the rise in thermal constraint costs. Wind curtailment reached 1.29TWh, up from 1.08TWh in September 2025, indicating a continued upward trend.

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 October, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £3m, resulting in a decrease of £2.0m compared to last month (£5m) and just £0.9m lower than October 2024.



The inertia expenditure fell in October despite higher wind generation, which made up around 34% of the total generation mix. The drop in inertia cost was linked to higher system demand compared to the previous month, which leads to more synchronous generators being self-dispatched to meet load. The increased presence of synchronous units naturally boosted system inertia, reducing the requirement for NESO to procure additional inertia services through the Balancing Mechanism.

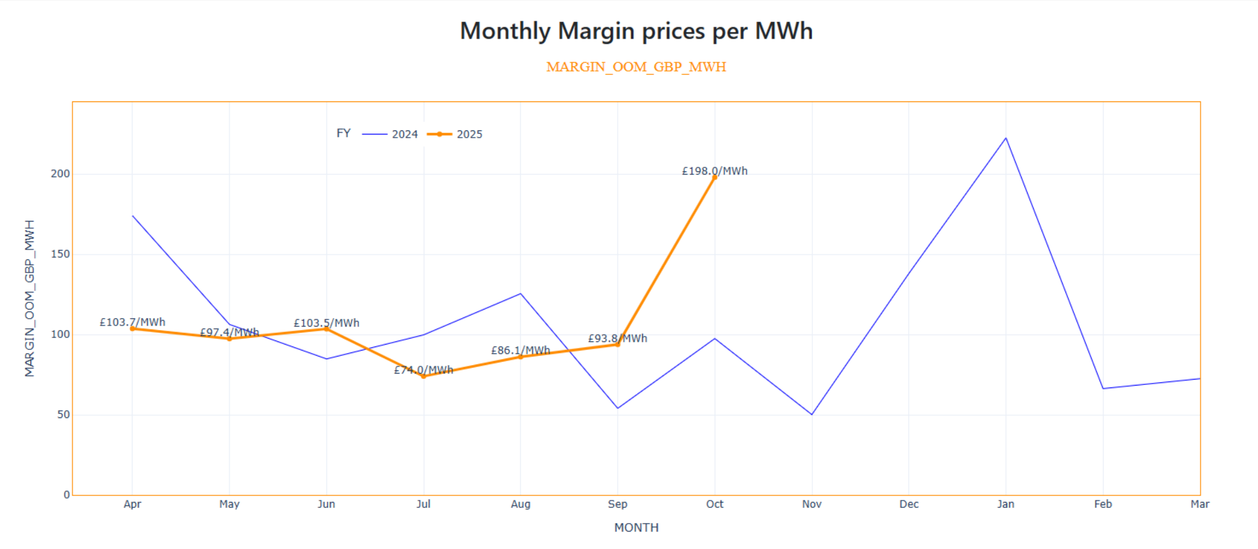
Reactive Costs/Volumes

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£2.1m Reactive costs have risen on last month reflecting an increase in power prices compared to September.	**+£3.3m** 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 increased to £198/MWh in October from £93.8/MWh in September 2025. This is a much sharper increase compared to the same period last year when prices between September 2024 and October 2025 rose from 54MWh to £97.5MWh.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: +£3.9 **Fast Reserve: -£1.5m** There was a 143 GWh increase in absolute volume of operating reserve to secure the system compared to September.	**Operating Reserve: +£7.2m** **Fast Reserve: -£3.6m** There was a 198 GWh decrease in the absolute volume of operating reserve required to secure the system compared to October 2024.

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**
+£0.4m There was a 4 GWh decrease in the absolute volume of actions compared to September. However, clearing prices for DC, DM, DR services were all higher this month than last.	**+£8.2 m** There volume of actions taken for response increase by 61 GWh compared to October 2025. Clearing prices were also higher year-on-year across all Dynamic Services.

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

		(a)	(b)	(b) - (a)	decrease ◂▸ increase
		Oct-25	Sep-25	Variance	Variance chart
Dynamic Services	DC	3.3	3.1	0.2	
	DM	5.2	4.6	0.7	
	DR	7.4	6.9	0.5	

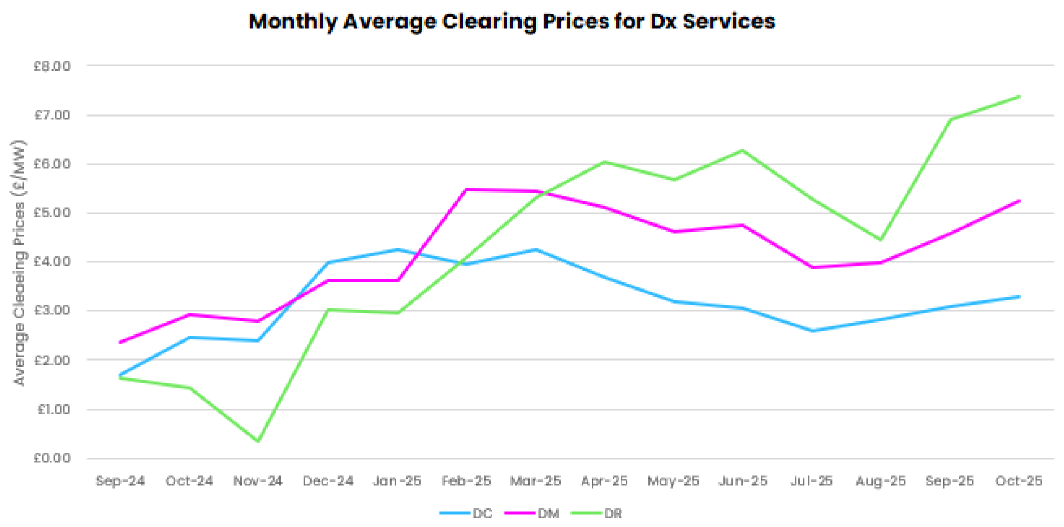
Dynamic Services Average Clearing Prices: October 2025 vs October 2024

		(a)	(b)	(b) - (a)	decrease ◂▸ increase
		Oct-25	Oct-24	Variance	Variance chart
Dynamic Services	DC	3.3	2.4	0.8	
	DM	5.2	2.9	2.3	
	DR	7.4	1.5	5.9	

Average clearing prices for Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR) rose in October, continuing the upward trend observed in September. This increase is largely driven by elevated procurement levels, which were influenced by higher wind generation on the system at the beginning and end of the month.

The requirement for Dynamic Moderation (DM) was raised in both August and October, resulting in increased procurement volumes and prices that are higher than typically expected for this time of year. This elevated procurement level is currently under review and is expected to reduce in the future.

Compared to October last year, all three dynamic services have seen a notable rise in average clearing prices, reinforcing the trend observed in September.

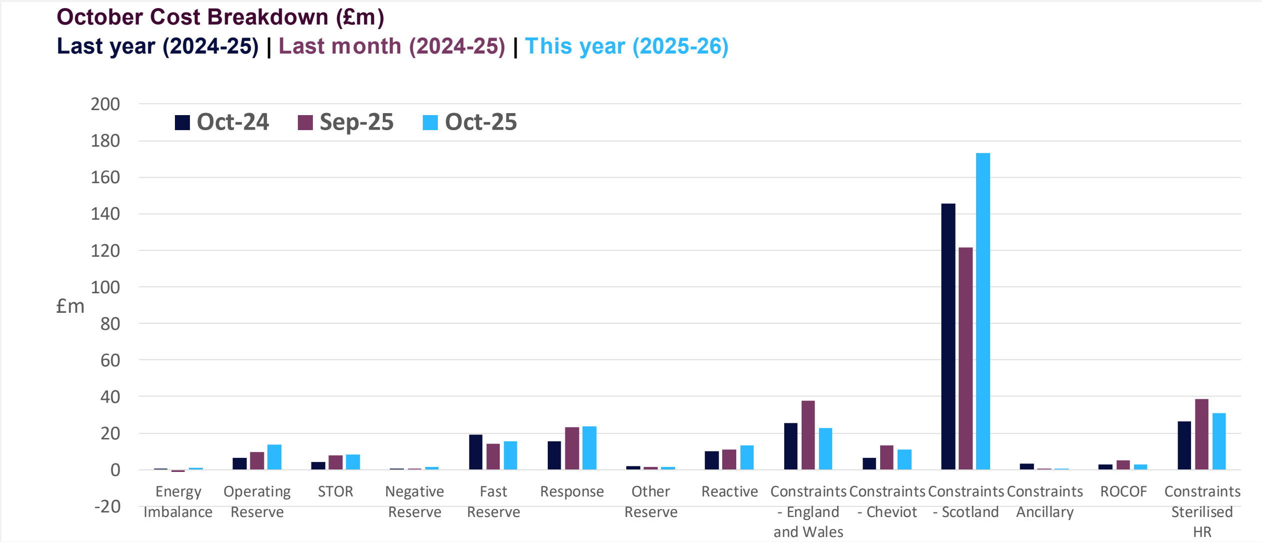


Comparison breakdown

Constraint costs increased by £24.3m compared to the previous month. Higher costs were seen in Scotland, though there was a decrease in Cheviot and England & Wales constraint costs (likely reflecting that the system required constraining further north in Scotland this month). The higher costs are in line with an overall increased wind outturn in October compared to September and, as such, higher volumes of wind curtailment required. Voltage spending increased, reflecting a combination of reactive equipment and an interconnector on outage, whilst inertia spending decreased month-on-month, reflecting the higher system demand which tends to bring more synchronous generation into the market. Total constraint costs increased 15% compared to October last year (from £209.9m to £241.4m), reflecting the fact that wind curtailment volumes rose 22% since last October as well.

Non-constraint costs increased by £12 million compared to September 2025, reflecting a rise in the costs of Operating Reserve, STOR, Negative Reserve, Fast Reserve, Response, Reactive and minor components since last month.

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 lowest cost.



COST SAVINGS

Cost Savings – Outage Optimisation

Total savings from outage optimisation amounted to approximately £33.5m in October 2025. This is an increase of roughly £14.8m relative to September 2025 (£18.7m). The most valuable action was the change of the running arrangement of Cottam 400kV which improved the transfer capacity of a constraint in the area by roughly 700 MW. The estimated cost saving for this action was roughly £13.1m.

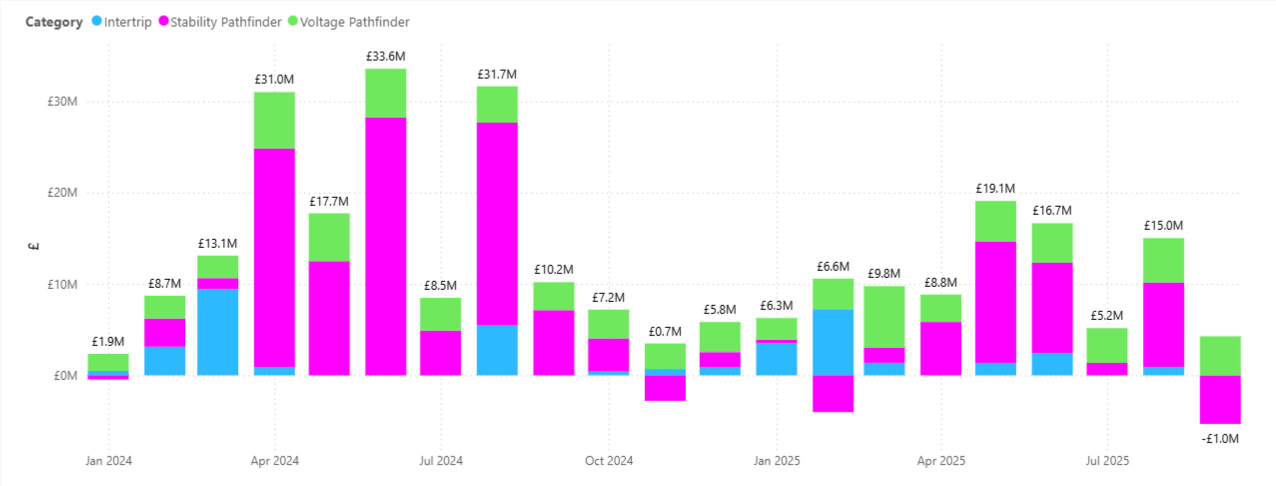
Cost Savings – Trading

The Trading team were able to make a total saving of £23.8m in October through trading actions as opposed to alternative BM actions, representing a 11% decrease on the previous month. Trading savings were mainly driven by margin trades, as due to higher prices on the continent than in GB, import trades were required. There was a significant drop in savings from constraint trading due to reduced requirements, however there was increased trading for voltage management due to increased wind outturn and more expensive prices in the BM. The day with the greatest trading savings was on the 7 October at a cost of £8.1m with savings being made on margin. The day with the greatest spend on trades was the 22 October at a cost of £3.8m 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 £63.8m in savings across 2025/26 to date (April – September 2025).

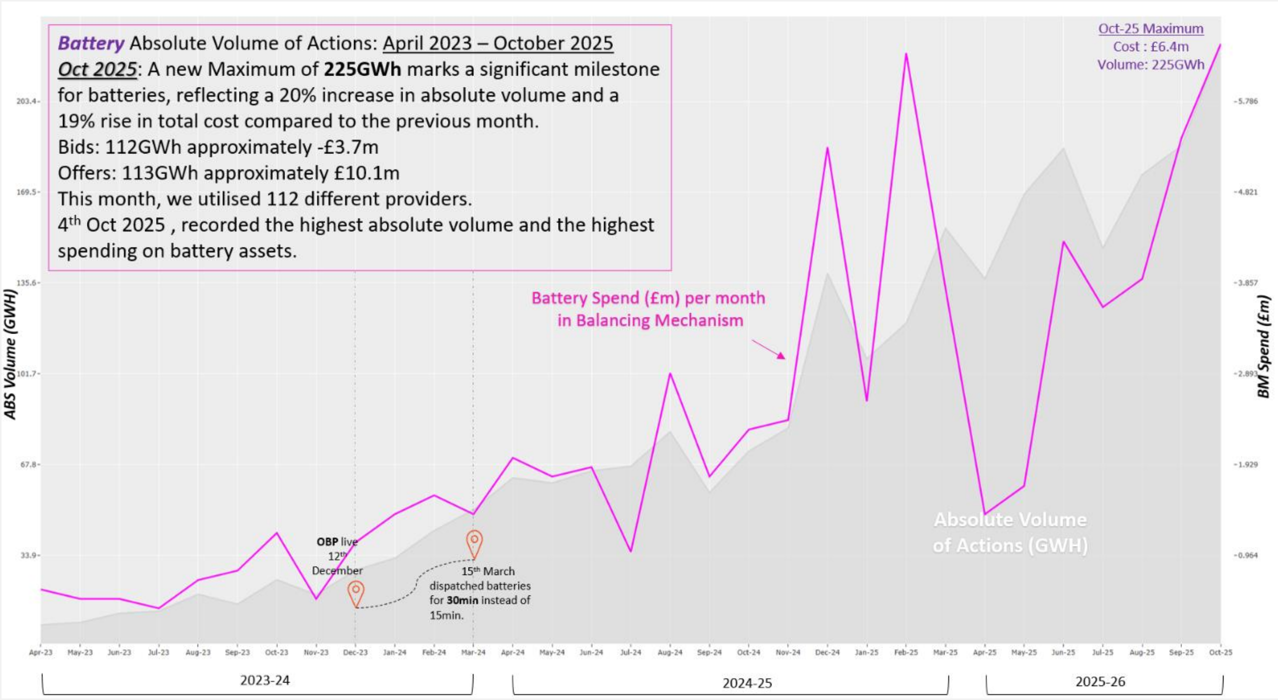
Monthly Savings from Network Services (NS)



NOTABLE EVENTS

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

October 2025



This graph illustrates a clear upward trend in both cost and volume over the observed period from April 2023 through October 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, October 2025 experienced an increase 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

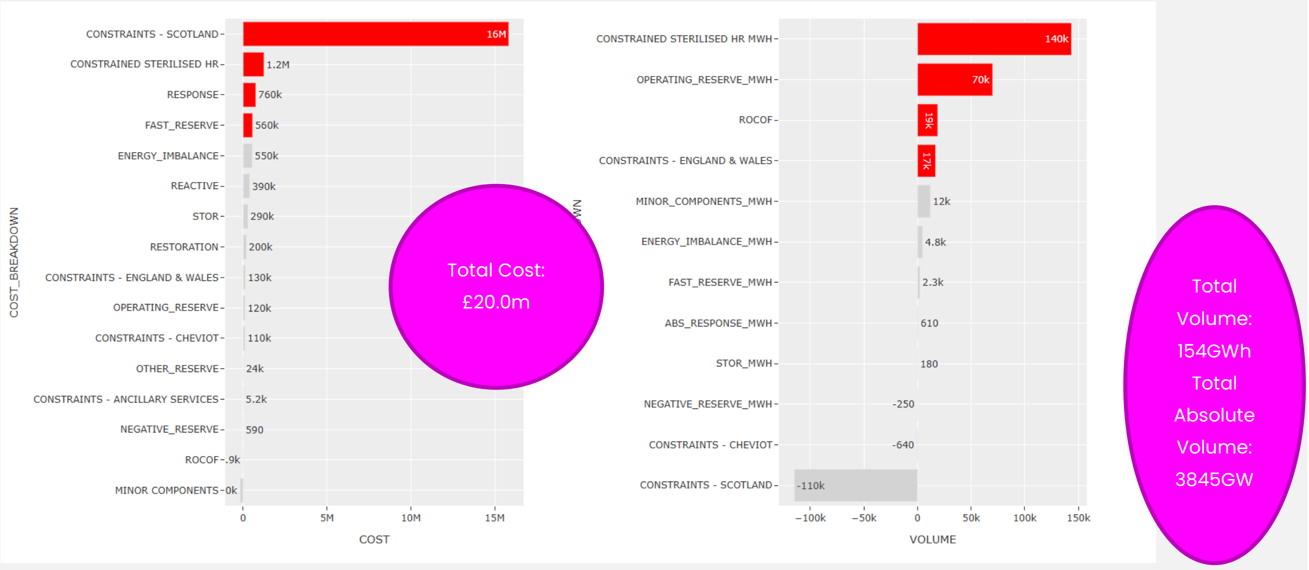
Daily Costs Trends

October's balancing costs were £326.2m which was higher by £36m than the previous month. This included eight days with a total cost above £15m (3rd, 4th, 5th, 6th , 8th, 9th, 25th, 31st) significantly greater than September which only had two. There were also a further eight days in October having a cost over £10m (1st, 2nd, 7th, 10th, 19th, 22nd, 26th, 30th). The daily average cost increased by £1.0m, from £9.5m in September to £10.5m.

The highest cost day was Thursday 9 October, with a total cost of approximately £20.0m similar to the highest costing day in September. These costs were driven by high levels of wind curtailment / constraint management in Scotland. Some actions were also taken to manage voltage levels.

The lowest cost day was Thursday 16 October, with a total cost of approximately £2.7m slightly higher than the lowest costing day in September. This day had very low wind outturn (approximately 63GWh) and there was very little constraint activity on this day. Some constraint limits were raised which gave us some more leeway.

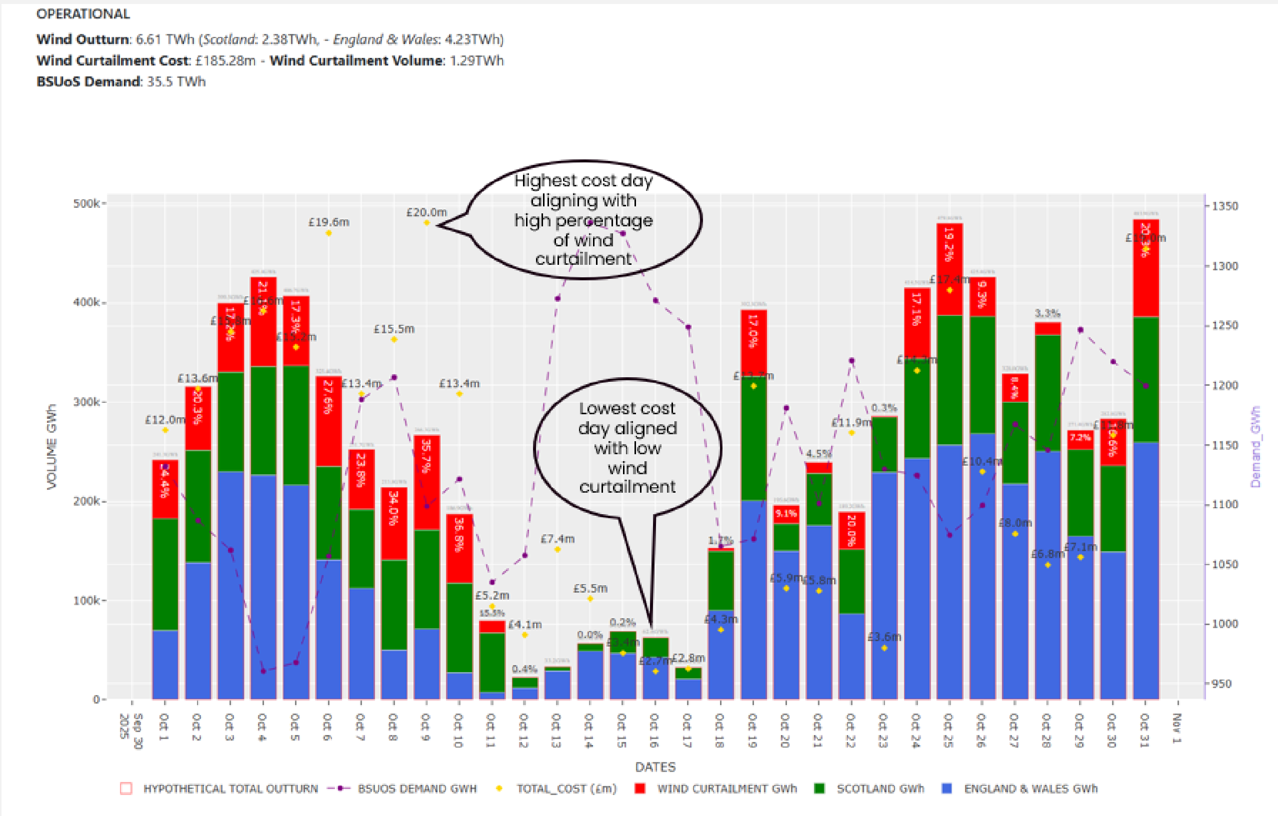
High-Cost Day – 9 Oct 2025



October 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).

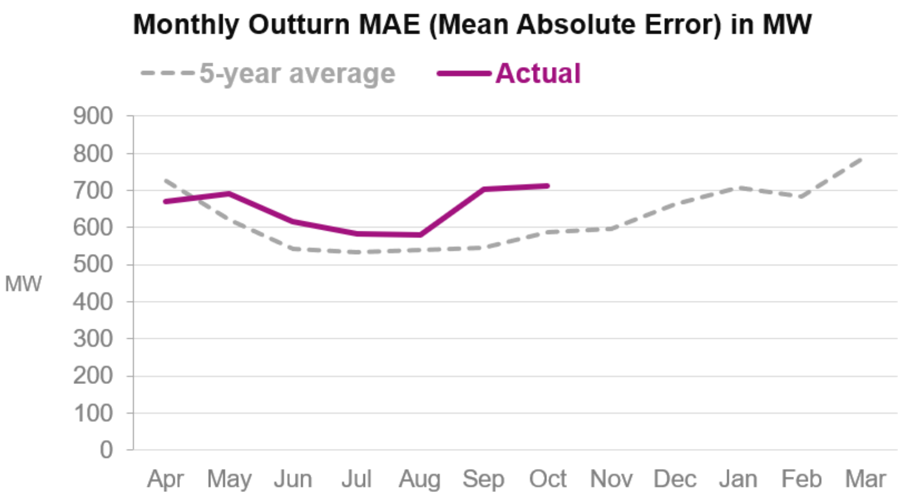
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

October 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**					

*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 October 2025 forecasting error averaged 711MW, which is a 123MW increase on the previous 5-year average of 588MW. YTD performance is currently 651MW, vs 5-year average of 584MW.

October had a stormy start, with the first named storm of the season (storm Amy, 3-4 October). Though winds were more settled in the middle of the month, complex cloud conditions made for difficult solar forecasting. The month then finished with more unsettled wet and windy weather, including the tail effects of storm Benjamin (23 Oct), as named by Meteo France.

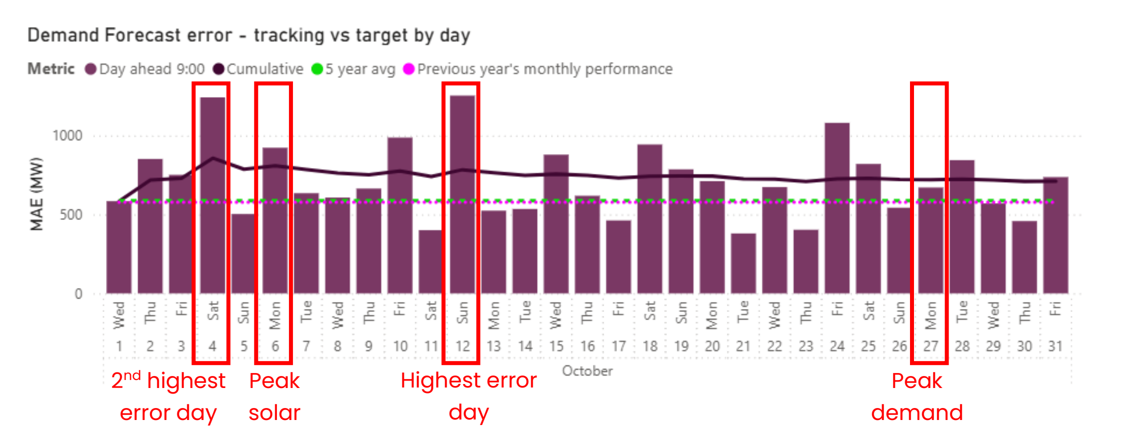
This month has been challenging. Changing weather forecasts causes regular large (>3GW) revisions to solar generation forecasts, at within-day timescales. These difficulties were observed across multiple external solar forecasts.

Free-energy offerings from retailers continue to be made available at short-notice to consumers. These were noted on October 4, 5, 24 and 25, most often for 2 hours periods.

Sunday, 26 October, saw the clock change from BST to GMT. This was followed by a week of school holidays in most local authorities. The initial period following any clock change is always challenging, as trained models re-adjust.

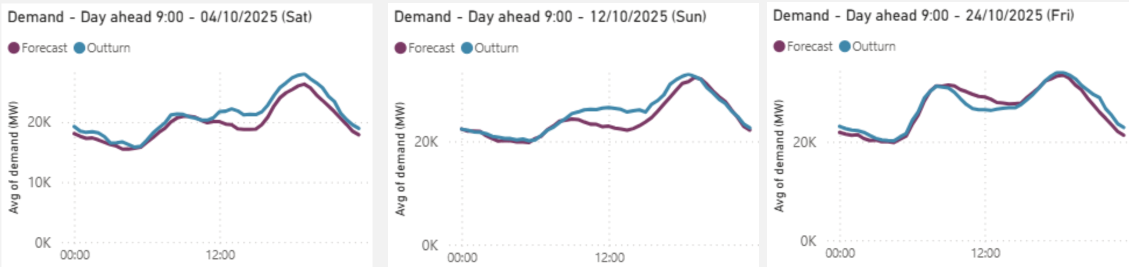
Solar generation peaked at 10.4GW on 6 October.

The largest absolute demand error this month was 3.8GW on 12 October, SP27.

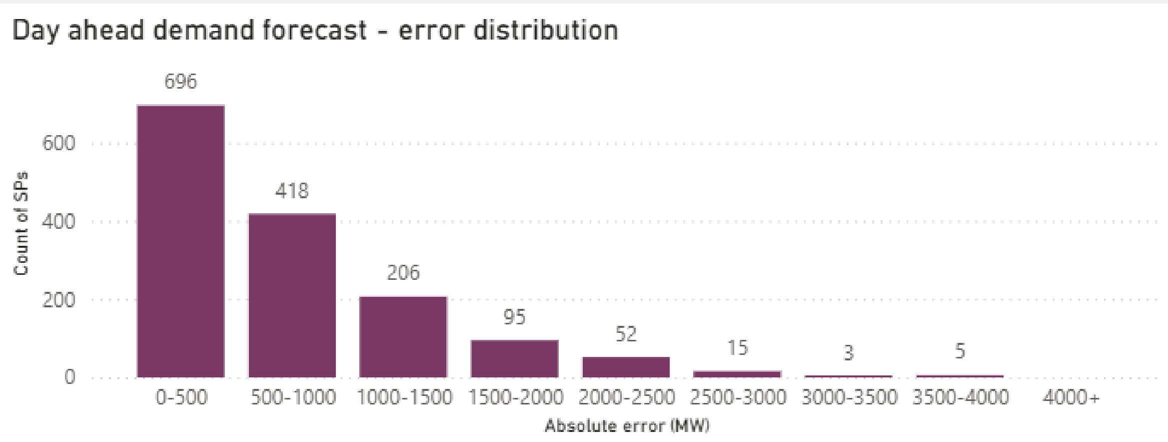


The minimum demand was 15.2GW on 5 October, SP10, while the maximum demand was 37.9GW on 27 October, SP36.

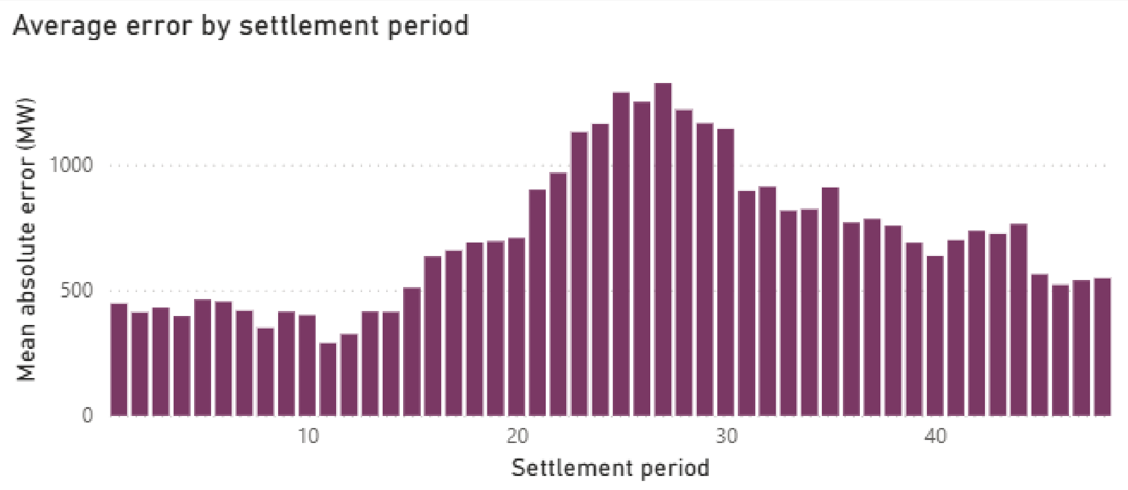
Days of Interest:



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 4, 12 and 24 October.

Day	Error (MAE)	Major causal factors
4	1242	Solar forecasting + profiling
12	1253	Solar forecasting errors
24	1080	Solar forecasting errors

Missed / late publications

There were no missed/late publications in October.

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 1, 2, 7, 13, 14, 15, 22, 27 and 29 October, with an accumulated total of 256MWh delivered. 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.

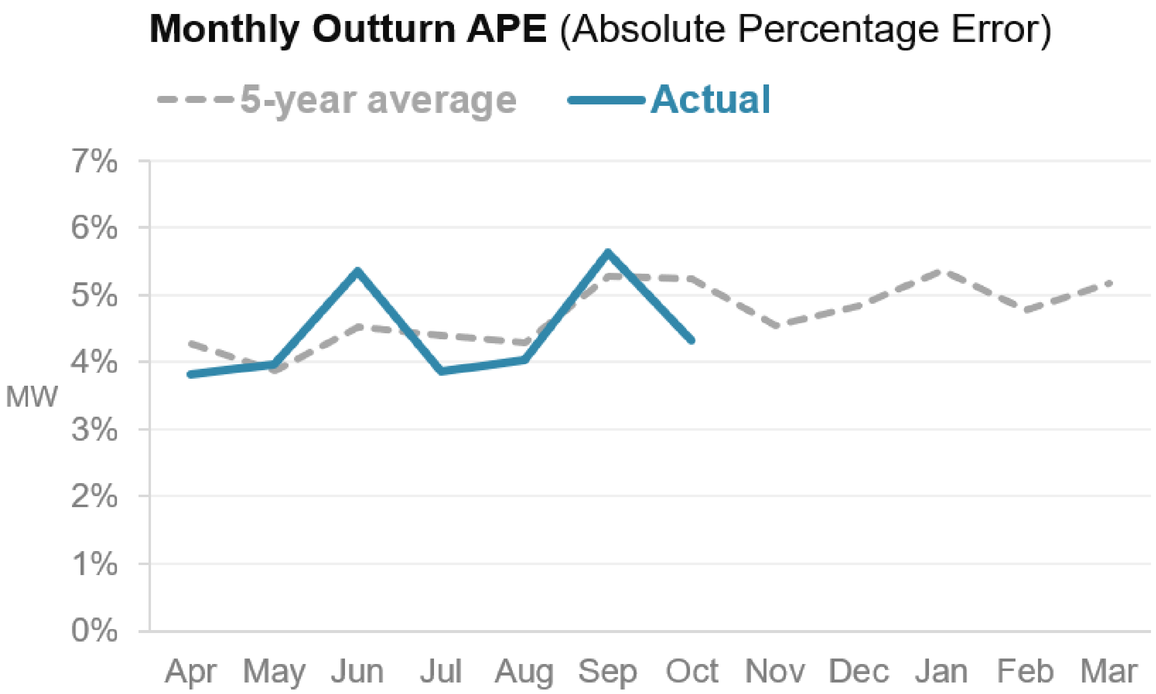
Sites deemed to have withdrawn availability are those that:

- 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.

October 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**					

*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 October 2025, BMU wind forecasting error averaged 4.33%, a 0.9% improvement on the 5-year average of 5.23%. YTD performance is currently 4.49%, vs 5-year average of 4.55%.

October began with storm Amy bringing strong and complex wind conditions, with up to 8GW of wind power predicted to cut-out under high wind (>25m/s) conditions at the Day Ahead position. The middle of the month was more settled. The month finished with more unsettled conditions with varied winds and rain, including storm Benjamin.

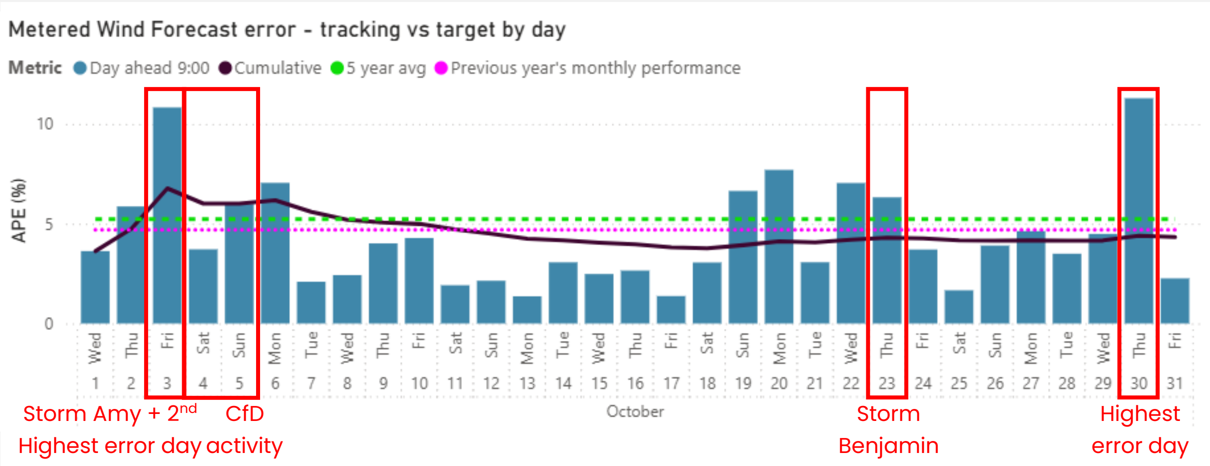
The forecast errors for October 3 and 30 were significantly higher than the remainder of the month, owing to fast changing wind speed forecasts. On both of these days, the within-day performance improved significantly as the weather forecasts adjusted.

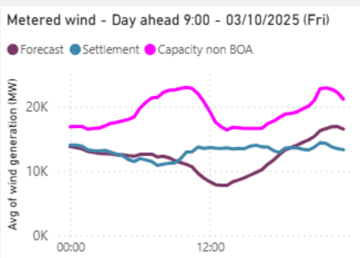
Contracts for Difference (CfD) activity occurred on 4 and 5 October, with close to 4.5GW of redeclarations received. Most of this activity is accounted for in the metric methodology.

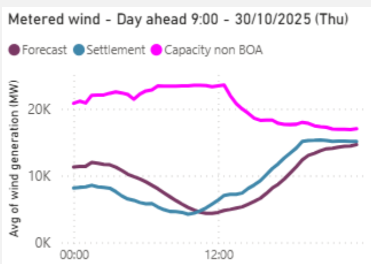
Work is underway building the new generation of wind generation forecast model prototypes. These make use of additional weather variables and functionalities added in the new platform.

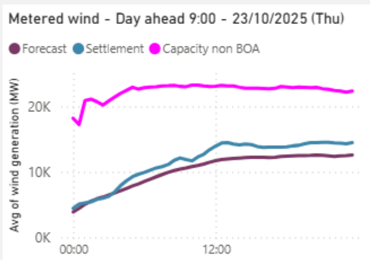
Metric-adjusted wind generation peaked at 16.2GW on 27 October, SP3.
Wind forecast absolute error peaked at 5.8GW on 3 October, SP28, during storm Amy.

Days of Interest:

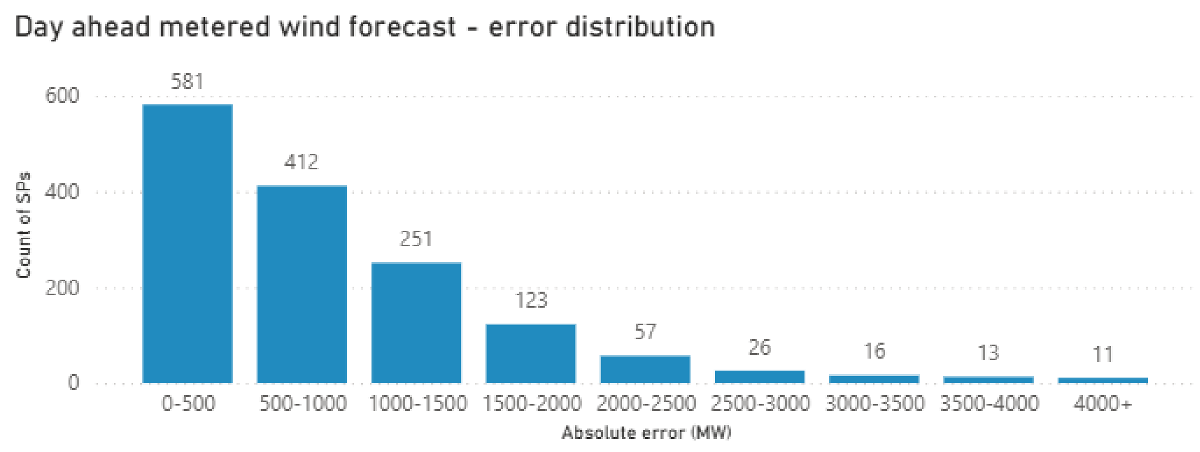








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
3	10.8	Wind speed forecast errors at day-ahead stage (Storm Amy)
30	11.3	Wind speed forecast errors at day-ahead stage

Missed / late publications

There were no missed/late publications in October.

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%					
Bids	45%	43%	51%	47%	40%	45%	45%					
Combined	44%	40%	40%	42%	36%	38%	36%					

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					
Offers – in merit Energy volume	148	205	356	215	279	359	437					
Offers – All in merit volume (System & Energy)	504	901	1052	529	943	971	1084					
Bids – Skipped volume	150	154	118	130	128	109	106					
Bids – in merit Energy volume	336	352	234	277	316	243	234					
Bids – All in merit volume (System & Energy)	815	995	1576	962	1344	1488	1815					
Combined Bid & Offer – skipped volume	213	225	234	208	214	226	239					

Supporting information

OCTOBER UPDATES

During October we have updated the Skip Rate Monitor tool within our Control Room to improve situational awareness of units which are in-merit for energy actions. Training of our shift teams on the improvements will continue until early December.

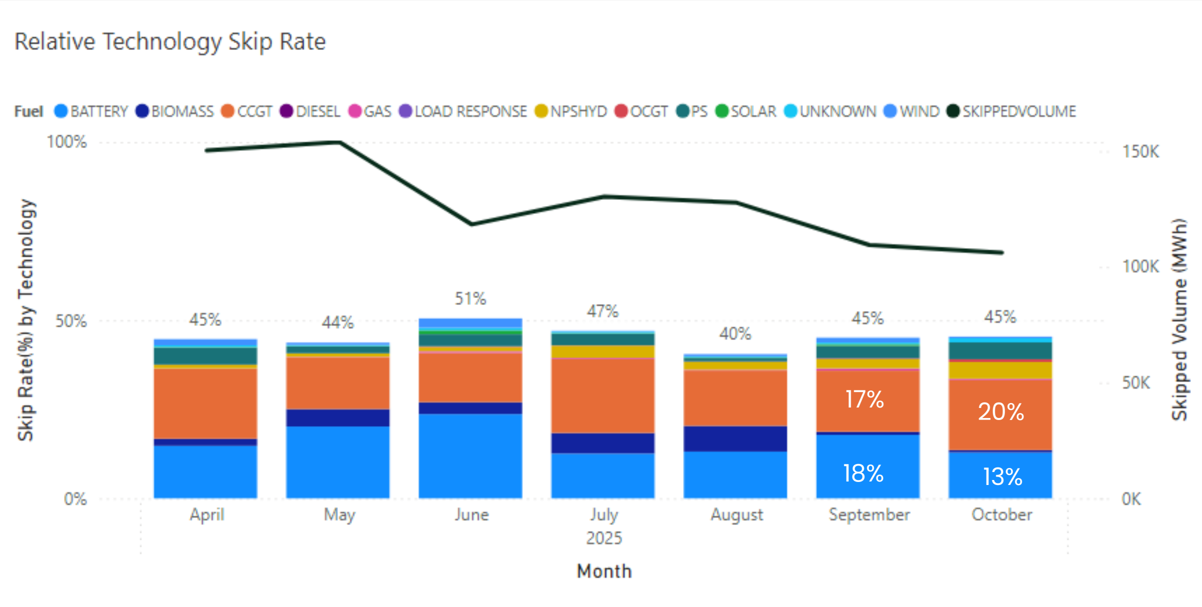
Work to reduce the occurrence of skips has continued with the on-boarding of a consultancy partner to work with us of phase 2 of the Root Cause Analysis (RCA) workstream, investigating the highest priority hypotheses to identify causation, and development of an action plan following the output of the Dispatch Strategic Review project.

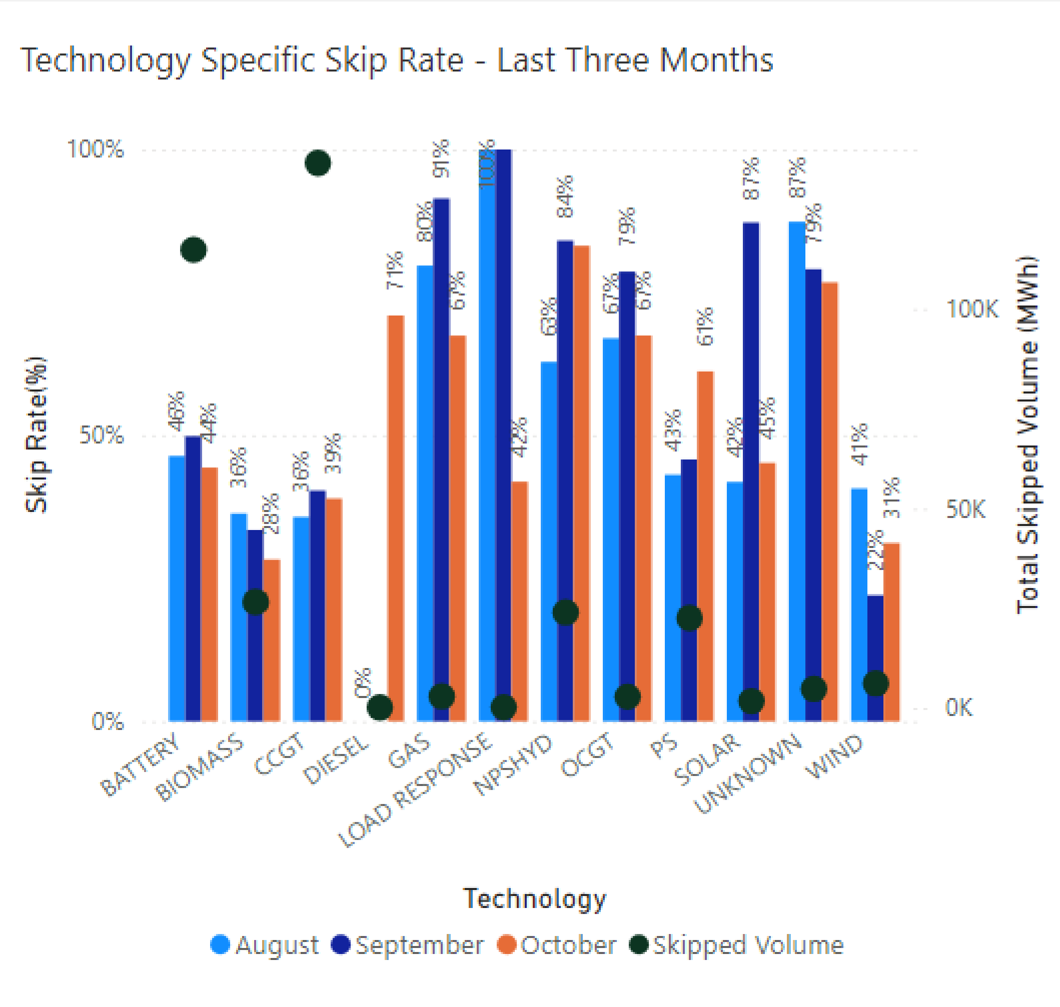
OCTOBER PERFORMANCE

The Offer skip rate has decreased from September (32%) to October (30%) but skipped volume has increased due to a higher volume of energy offer actions taken in October. The Bid skip rate has remained constant in September and October (45%) and the skipped volume is almost flat (109GWh in September and 106GWh in October). The combined bid and offer skip rate has decreased from 38% in September to 36% in October.

Bids

CCGTs accounted for a higher proportion of skipped volume in October (20%) compared to September (17%) and the Technology Specific skip rate for CCGTs has decreased from 40% to 39%. Batteries account for a lower proportion of the skip rate in October (13%) compared to September (18%) and the Technology Specific skip rate has decreased from 50% to 44%. A significant proportion of bid skipped volume (29%) is due to Mandatory Frequency Response (MFR) – either units being accepted out of merit to position them to deliver MFR or units skipped due to being held to deliver MFR.

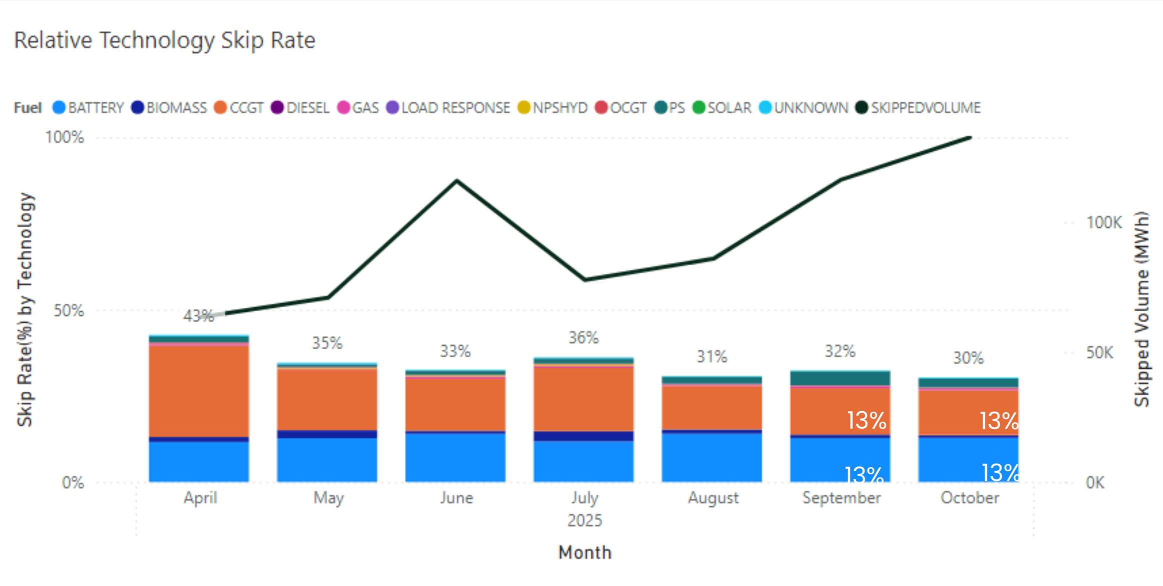


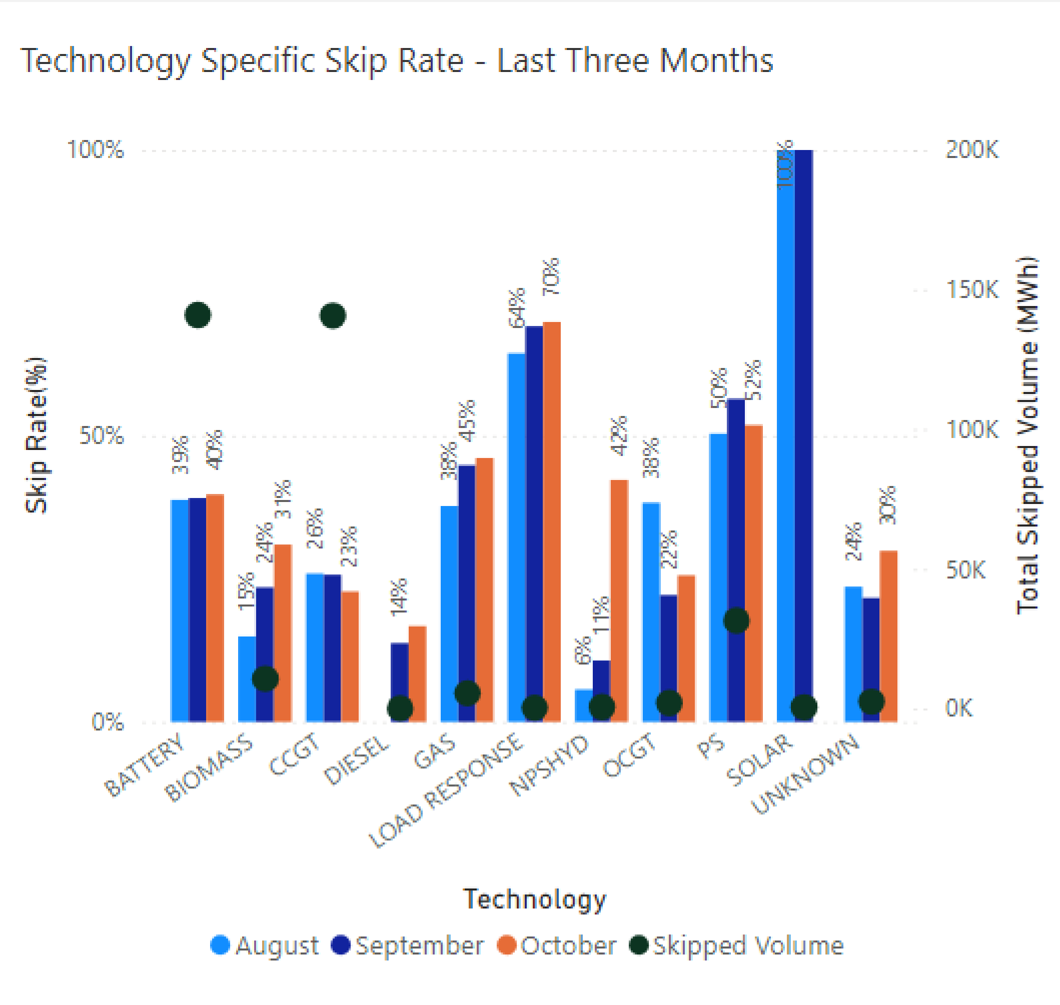


Offers

CCGTs account for the same proportion of skipped volume in October and September (13%), and the Technology Specific skip rate has decreased from 26% in October to 23% September. Batteries account for the same proportion of skipped volume in October and

September (13%), and the Technology Specific skip rate has increased slightly from 39% in September to 40% in October. A significant proportion of offer skipped volume (22%) is due to Mandatory Frequency Response (MFR) – either units being accepted out of merit to position them to deliver MFR or units skipped due to being held to deliver MFR.





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 Response (DSR) units, however work is ongoing to better define and report on these units.

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.

October 2025-26 performance

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

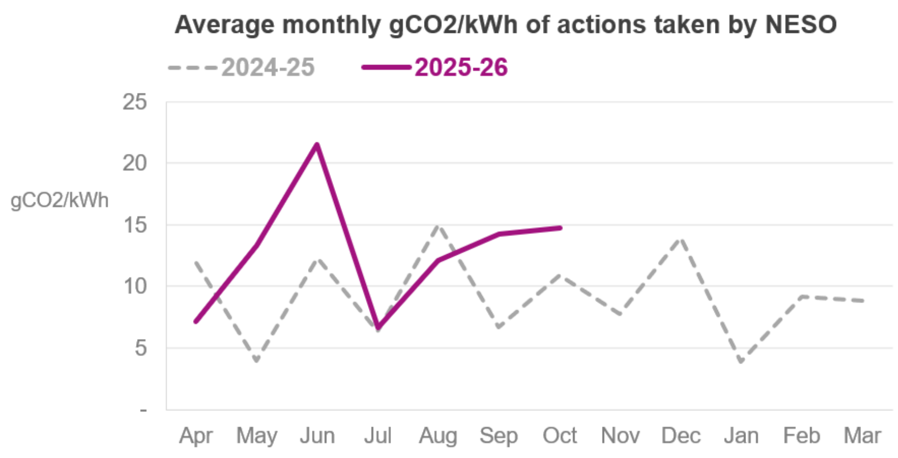


Table: Average monthly gCO2/kWh of actions taken by NESO

	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					

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 October, the average monthly carbon intensity from NESO actions was 14.75g/CO_2/kWh. This is 0.53g/CO_2/kWh higher than September and 1.93g/CO2/kWh higher than the YTD average of 12.82g/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 83.82/CO_2/kWh which took place on 9 October 2025 at 00:30. This is 26.59/CO_2/kWh higher than the highest point in September 2025 of 57.23g/CO_2/kWh.

On 9 October there was lower wind output than forecast. NESO intervention was required to manage a number of system constraints and system stability.

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.

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

Supporting information

No reportable voltage or frequency excursions during October.

[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.

October 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					
Integrated Energy Management System (IEMS)	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					
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0					

Supporting information

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

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