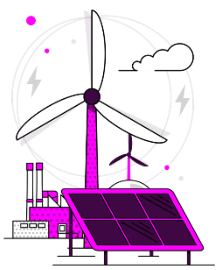
26 August 2025

Monthly Incentives July 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 (NESO PAG) Document 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 appending 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 6-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	17 working day of following month
Quarterly	• Reported Metrics • Performance Objectives Progress updates	17 working day of 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 objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the DD&T investment portfolio. 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 July 2025:

Reported Metric		Performance
1	**Balancing Costs**	**£167m**
2	**Demand Forecasting**	Forecasting error of **584MW**
3	**Wind Generation Forecasting**	Forecasting error of **3.87%**
4	**Skip Rates**	Post System Action (PSA) Offers: **36%** Bids: **47%** Combined: **42%**
5	**Carbon intensity of NESO actions**	**6.64 gCO_2/kWh** of actions taken by the NESO
6	**Security of Supply**	**0** instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. **0** voltage excursions
7	**CNI Outages**	**1** planned and **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.

July 2025 performance

Figure: 2025-26 Monthly balancing cost outturn versus benchmark

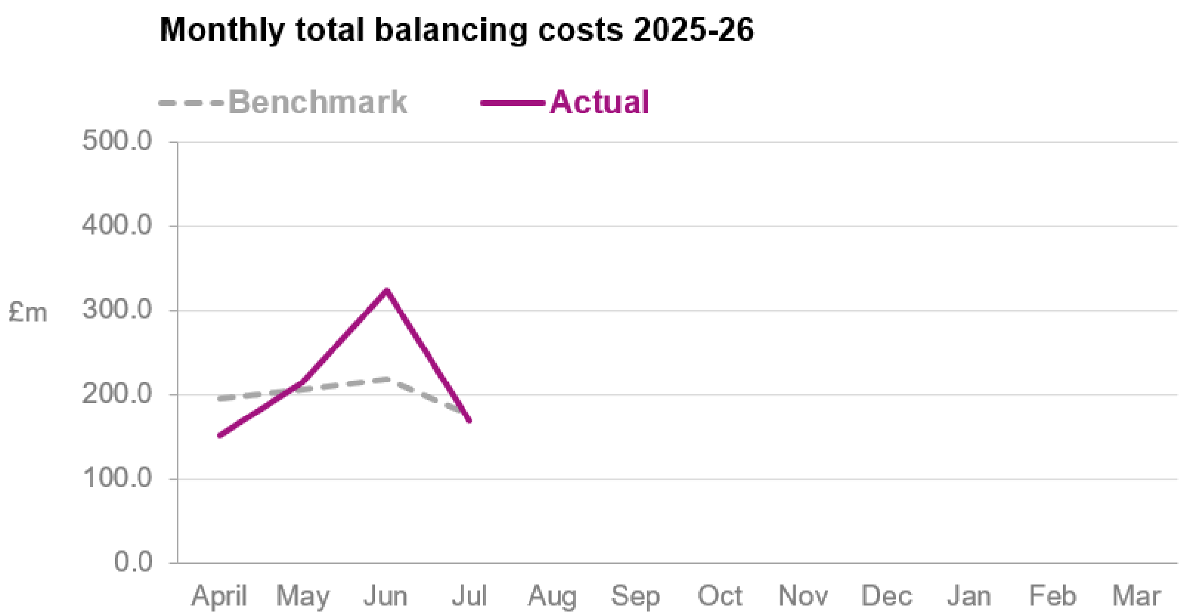


Table: 2025-26 Monthly breakdown of balancing cost benchmark and outturn

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									17.5
Average Day Ahead Baseload (£/MWh)	81	77	73	80									n/a
Benchmark*	195	206	219	176									797
Outturn balancing costs[1]	**152**	**215**	**324**	**167**									**858**

[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

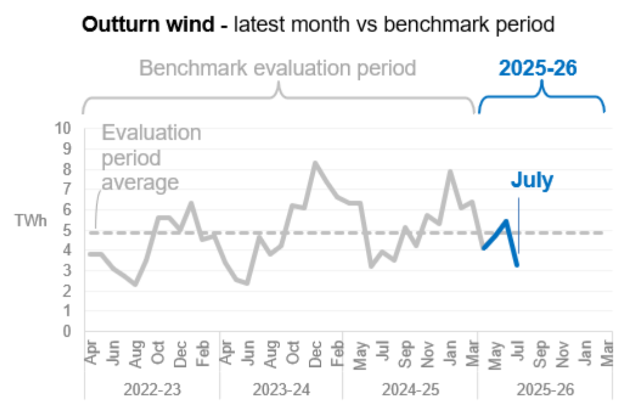
BALANCING COSTS METRIC & PERFORMANCE

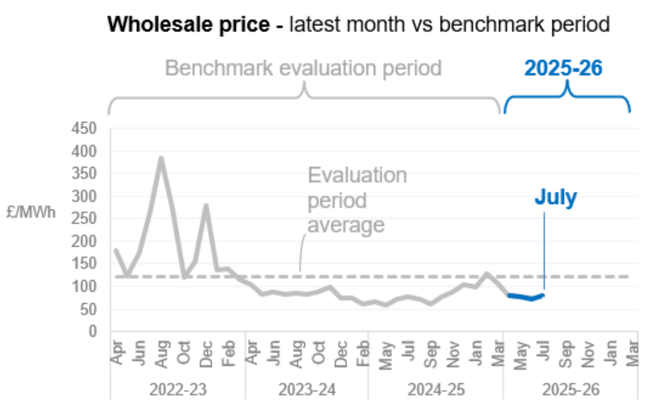
This month's benchmark

The July benchmark of £176m is £43m lower than June 2025 and reflects:

- An **outturn wind** figure of 3.3 TWh that is lower than the average during the benchmark evaluation period (the last three years, where the average monthly wind outturn was 4.9 TWh) and is lower than May 2025's figure (5.4 TWh).
- An average monthly **wholesale price** (Day Ahead Baseload) that has increased compared to June 2025 and is higher than the previous year. However, it remains lower than the evaluation period average.

The lower wind outturn has caused the decrease in July's benchmark compared to June but has been somewhat negated by higher wholesale prices.





Variable	July 2025	June 2025	July 2024
Average Wholesale Price (£/MWh)	**80**	**-7**	**-9**
Total Wind Outturn (TWh)	**3.3**	**+2.1**	**+0.2**
Benchmark (£m)	**176**	**+43**	**-3**

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

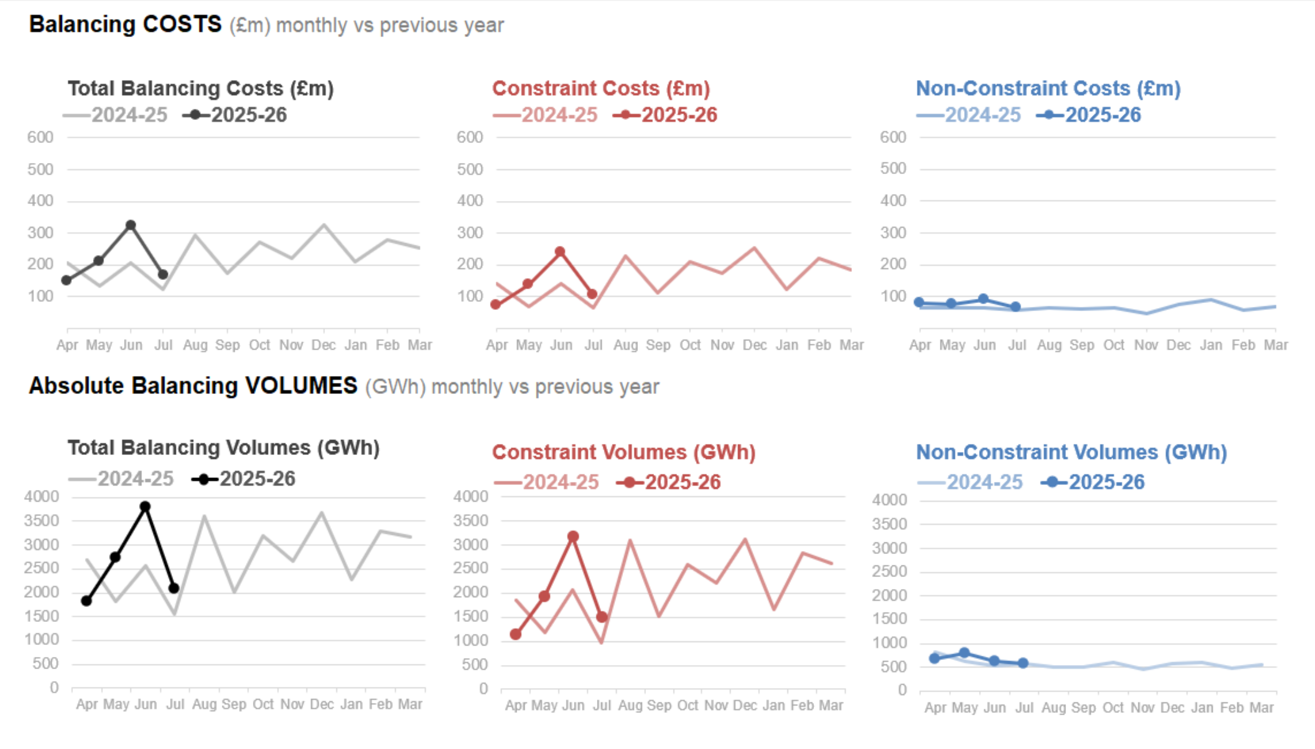
Balancing Costs - Overview

The total balancing cost for July was £167m, which is £9m (~5%) below the benchmark.

Wind outturn in July saw a significant reduction compared to the previous month to its lowest level for the year so far at 3.3 TWh, down from 5.4 TWh in June. This has supported a significant reduction in constraint costs, with wind curtailment volumes down to 428GWh from 1,159GWh last month. Voltage and stability constraints also saw a significant reduction in costs compared to recent months, in part linked to higher transmission system demand outturn than previous months this summer, particularly during overnight periods. Low demand can mean that some synchronous units (mostly CCGTs) that usually provide reactive and inertia support are not self-dispatched, which forces us to procure those services through the Balancing Mechanism. This requirement was subsequently reduced in July.

There are still ongoing outages across Scotland which took place during the month, influencing constraint costs in the region. However, low demand meant that this effect was reduced in July compared to previous months this year. However, thermal constraints were higher than July 2024.

Average wholesale prices increased by £7/MWh from June 2025 and £9/MWh from July 2024. The volume weighted average (VWA) price of bids was £5.2/MWh, which is less expensive than last month's price of -£21.2/MWh. The VWA price for offers has decreased from £129.2/MWh to £124.6/MWh. Non-constraint costs have decreased by £27.6m, following a decrease in the absolute volume of non-constraint actions decreasing by 29GWh.

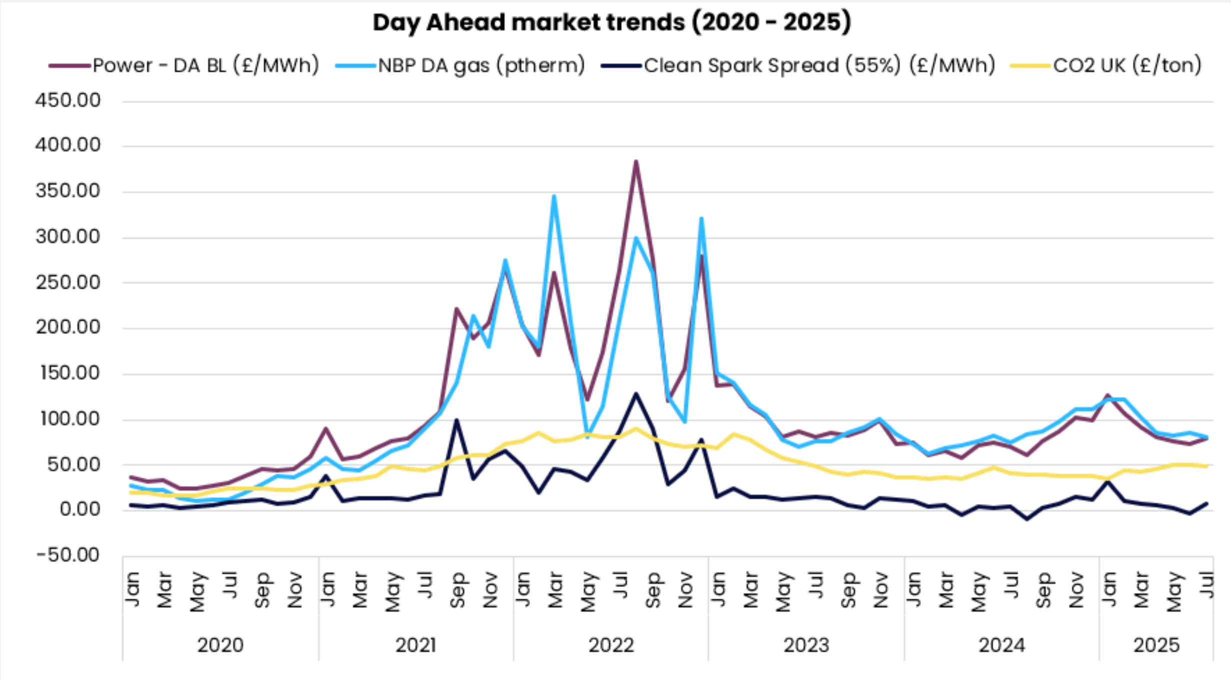


*Please note that the charts above now show absolute volume rather than net volume.

System and Market Conditions

Market trends

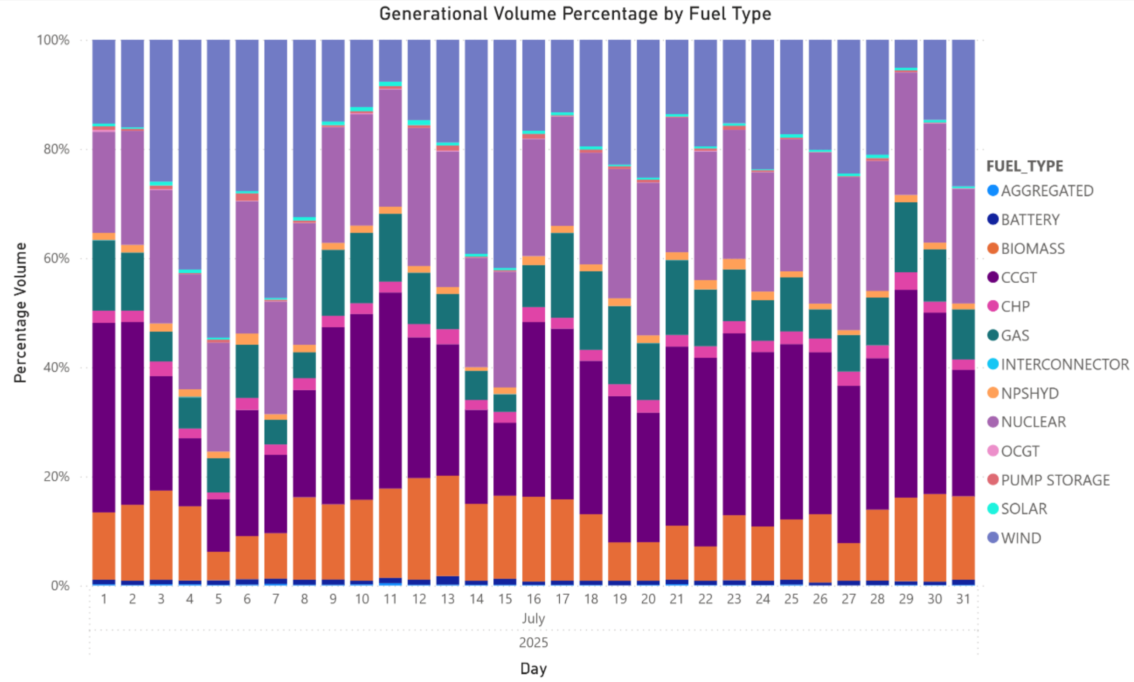
Power prices in July ended the downwards trend we've seen in 2025, increasing to £80.25/MWh, with a subsequent rise in the Clean Spark Spread Price up to £7.83/MWh. Both the Power and Clean Spark Spread Prices are similar to April 2025. In contrast, Gas prices dipped in July, falling to 80.94p/therm, the lowest price since July 2024 and CO2 prices also had a slight dip as well. A decrease in wind outturn projections contributed to the increase in Power prices, whilst the European Parliament adopted more flexible gas storage rules, influencing a potential reduction in the competition for the procurement of LNG (Liquefied Natural Gas), leading to lower Gas prices.



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

Generation Mix

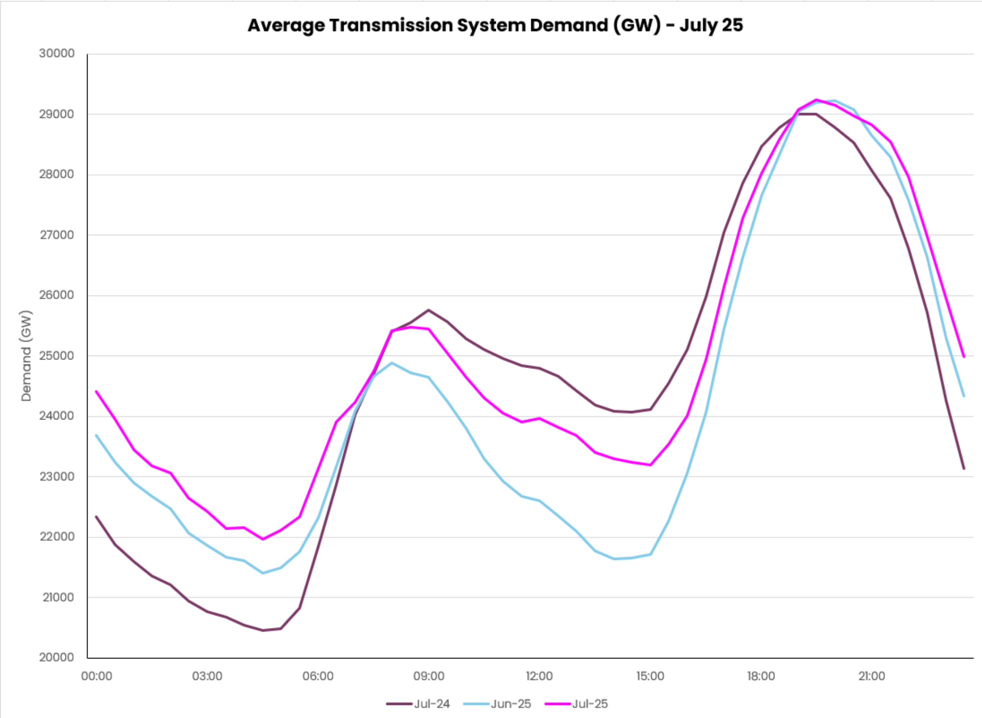
In July we saw that CCGT's made up the largest share of the generation mix at 27.8%, which was higher than the 19.7% we saw in June. Wind made up the second largest share at 23.6% which is a decrease of 14.9% compared to June, and a corresponding month on month decrease in the absolute volume of nearly 2089GWh.



*Generation mix includes exports from interconnectors.

Transmission System Demand

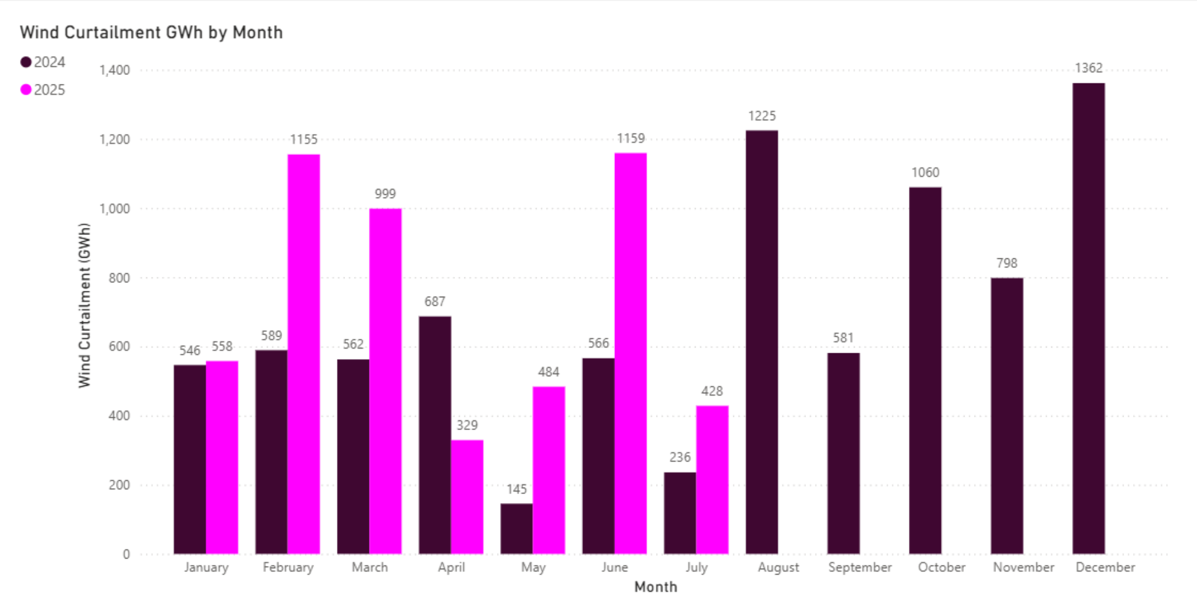
In July the average Transmission System Demand (TSD) was generally higher than the previous month, particularly in the middle of the day or overnight. Comparing July to the same month in 2024, the average TSD was notably higher during the overnight period, with the average TSD being on average 1700MW higher between midnight and 6am. During the middle of the day (9am – 3pm), July 2025 had an average TSD that was on average 740MW lower than July 2024.



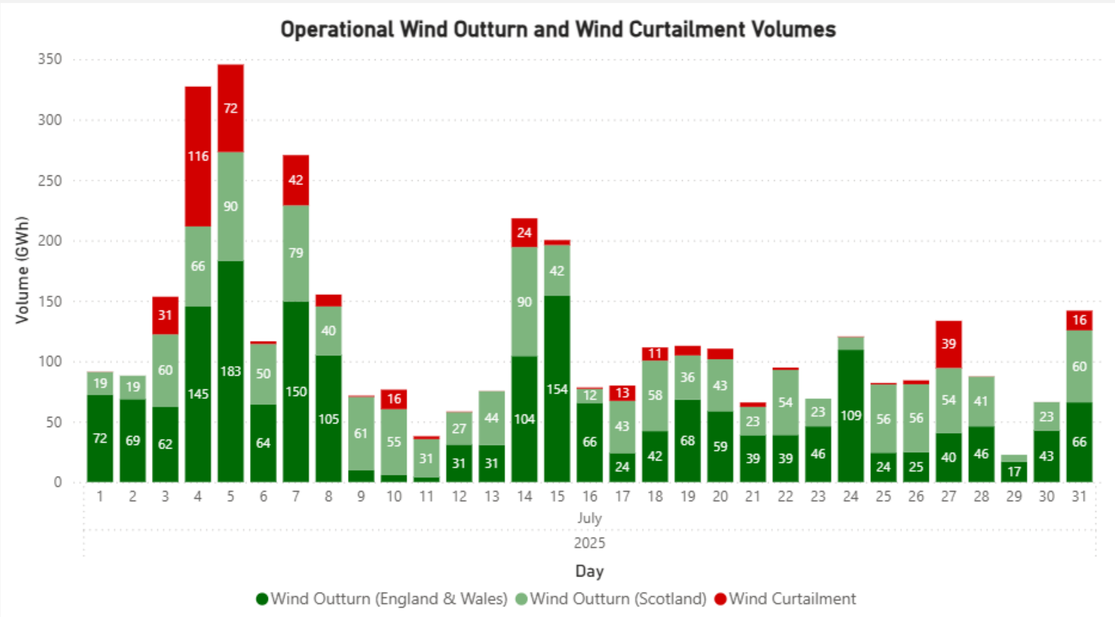
Wind Outturn

July started with some unsettled weather at the start of the month linked to frontal systems. Higher pressure brought more settled weather from the second week before returning to more unsettled weather as the month went on.

Overall wind outturn in July (3.3TWh) was down significantly on the previous month (5.4TWh) and close to the July 2024 outturn (3.5TWh). July consequently saw a large reduction in wind curtailment, at 428GWh compared to 1,159GWh in June. The majority of this curtailment was seen early in the month, coinciding with more unsettled weather.



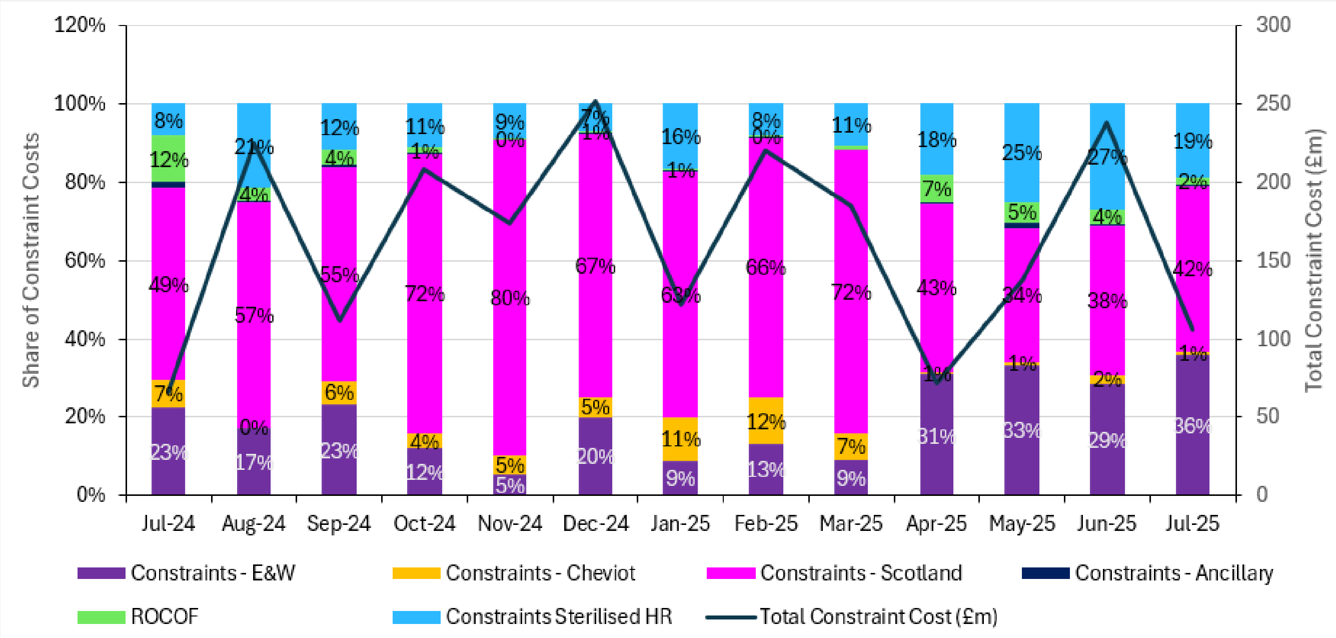
The day with the highest volume of wind curtailment occurred on 4 July with 116GWh which was also the highest cost day of the month.



Constraints

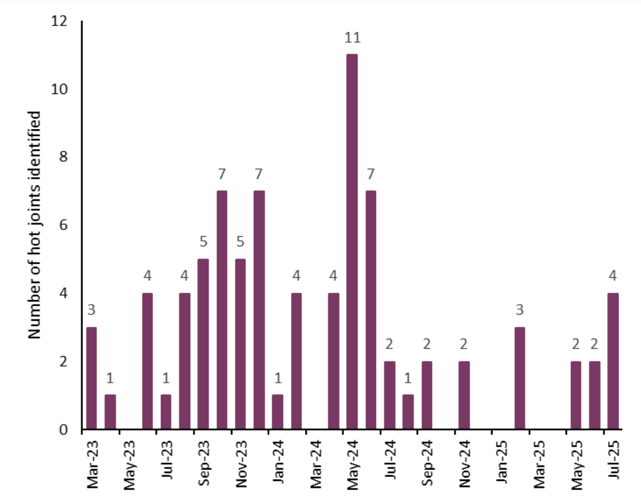
Constraint costs decreased from £237.5m in June to £106.0m in July, a reduction of £131.5m. This decrease was observed across all constraint categories. The share of constraints therefore remained similar to the previous month, with the largest changes seen in Constrained Sterilised HR and Constraints – England & Wales which saw shares decrease to 19% and increase to 36% respectively.

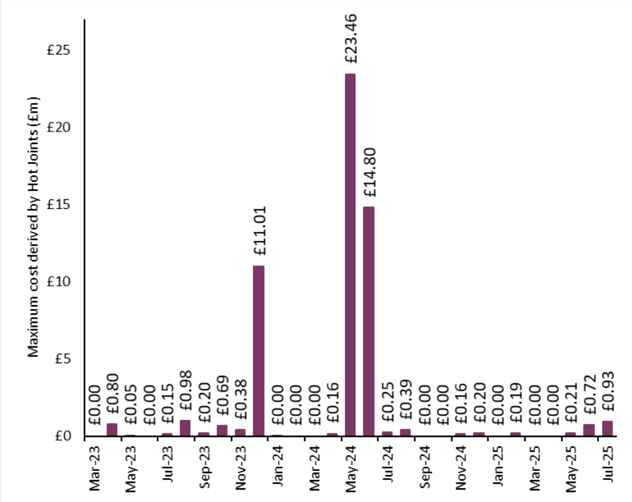
Wind outturn across England & Wales and Scotland was closer to the seasonal average, resulting in July being a lower month for wind curtailment, and saw a significant decrease compared to June (which had abnormally high wind outturn for the time of year).



Network Availability

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. Four hot joints were identified in July. The cost impact remained low with a maximum estimated value of £931k.





BALANCING COSTS DETAILED BREAKDOWN

Balancing Costs variance (£m): July 2025 vs June 2025

		(a) Jun-25	(b) Jul-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	12.4	-0.2	(12.6)	
	Operating Reserve	19.5	7.2	(12.2)	
	STOR	4.2	4.9	0.7	
	Negative Reserve	1.1	1.2	0.1	
	Fast Reserve	10.8	12.1	1.2	
	Response	21.0	17.8	(3.2)	
	Other Reserve	0.5	0.6	0.1	
	Reactive	10.1	12.0	1.9	
	Restoration	8.3	3.4	(4.9)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	0.7	2.0	1.3	
Constraint Costs	Constraints - E&W	67.8	34.6	(33.3)	
	Constraints - Cheviot	5.4	0.9	(4.5)	
	Constraints - Scotland	91.0	46.6	(44.4)	
	Constraints - Ancillary	0.7	0.2	(0.5)	
	ROCOF	8.4	2.2	(6.1)	
	Constraints Sterilised HR	64.2	21.0	(43.2)	
Totals	Non-Constraint Costs - TOTAL	88.5	60.9	(27.6)	
	Constraint Costs - TOTAL	237.5	105.5	(132.0)	
	Total Balancing Costs	**326.0**	**166.5**	**(159.5)**	

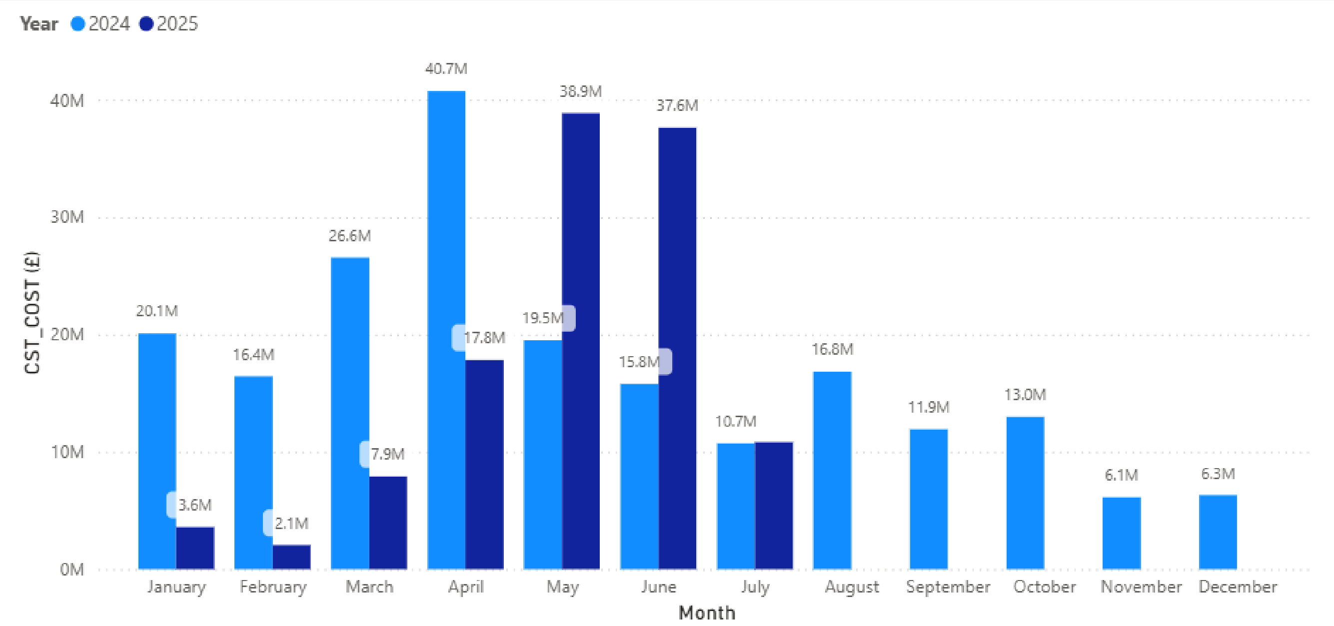
As shown in the totals from the table above, constraint costs decreased by £132.0m and non-constraint costs decreased by £27.6m which results in an overall decrease in costs of £159.5m compared to June 2025.

Constraint Costs/Volumes

Comparison versus previous month	Comparison versus same month last year
Constraint-Scotland & Cheviot: -£48.9m **Constraint – England & Wales: -£33.3m** **Constraint Sterilised Headroom: -£43.2m** Constraint costs decreased by £132.0m in July, coinciding with a 402 GWh decrease in the absolute volume of actions. Wind outturn decreased significantly in July resulting in a reduced volume of actions to manage constraints. **ROCOF: -£6.1m** In July, the system's outturn inertia (including market-provided, stability assets, and synchronous plants used for voltage support) resulted in lower volumes to meet the minimum inertia requirements of the system. Lower wind outturn in July contributed to reduced inertia regulation as non-synchronous generation met a larger proportion of the self-dispatched generation mix.	**Constraints – Scotland & Cheviot: +£10.6m** **Constraints – England & Wales: +£20.2m** **Constraints Sterilised Headroom: +£15.6m** Constraint costs have increased by £41.1m compared to last year. Wind outturn was slightly lower than July 2024 but ongoing outages in Scotland and Northern England acted to push costs up year-on-year. **ROCOF: -£4.6m** There was a decrease in inertia spend compared to July 2024, coinciding with a reduction in constraint volumes. The gradual addition of assets commissioned through the Stability Pathfinder Phase 2 is expected to positively contribute to inertia levels in the system, resulting in reduced ROCOF spending.

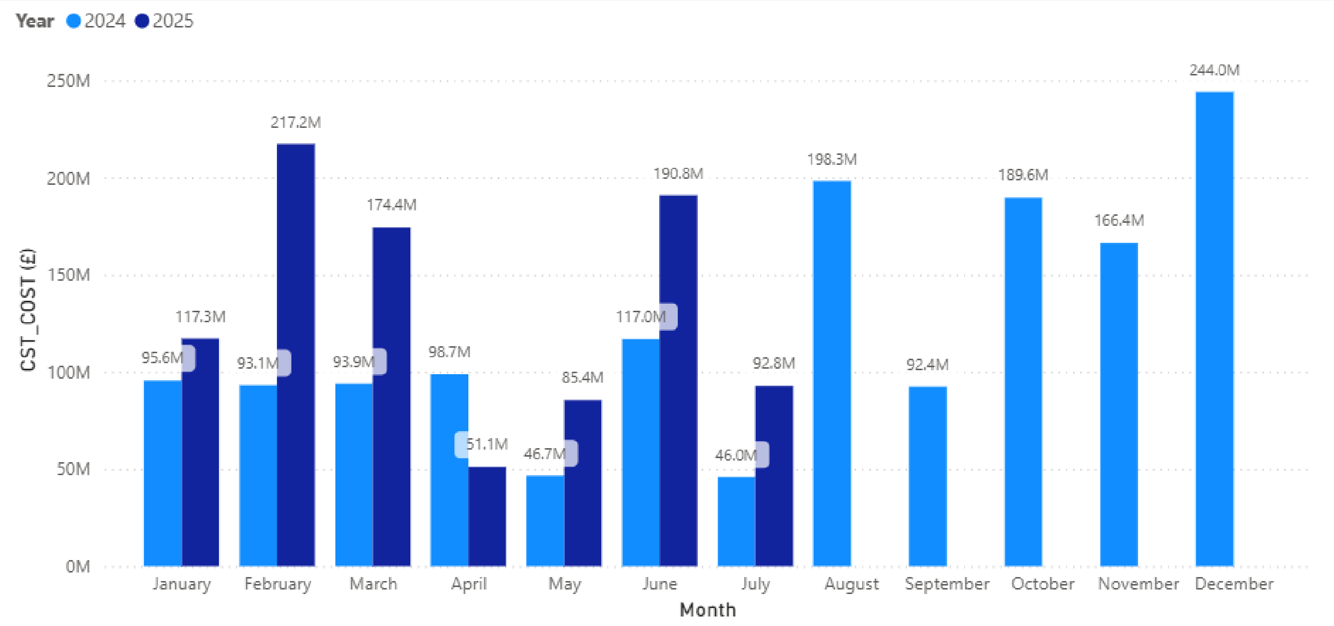
Voltage – Monthly system cost of synchronisation actions for voltage control across 2024 and 2025:

Synchronisation costs are associated with specific actions required to support voltage in the system. These actions involve units that are instructed to provide MVArs and maintain voltages within SQSS limits. It is a highly location-dependent issue, so only a limited set of assets are effective in voltage support, depending on their location. In July, the system synchronisation costs (what it costs to the system, which factors in energy replacement and headroom among others) amounted to £10.8m, a significant reduction of £26.9m on last month, and just £0.1m higher than July 2024.



Voltage spending is usually higher overnight due to lower demand at this time of day. This 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. In July, overnight demand was notably higher compared to last month and July last year. This has supported lower voltage spend for the month.

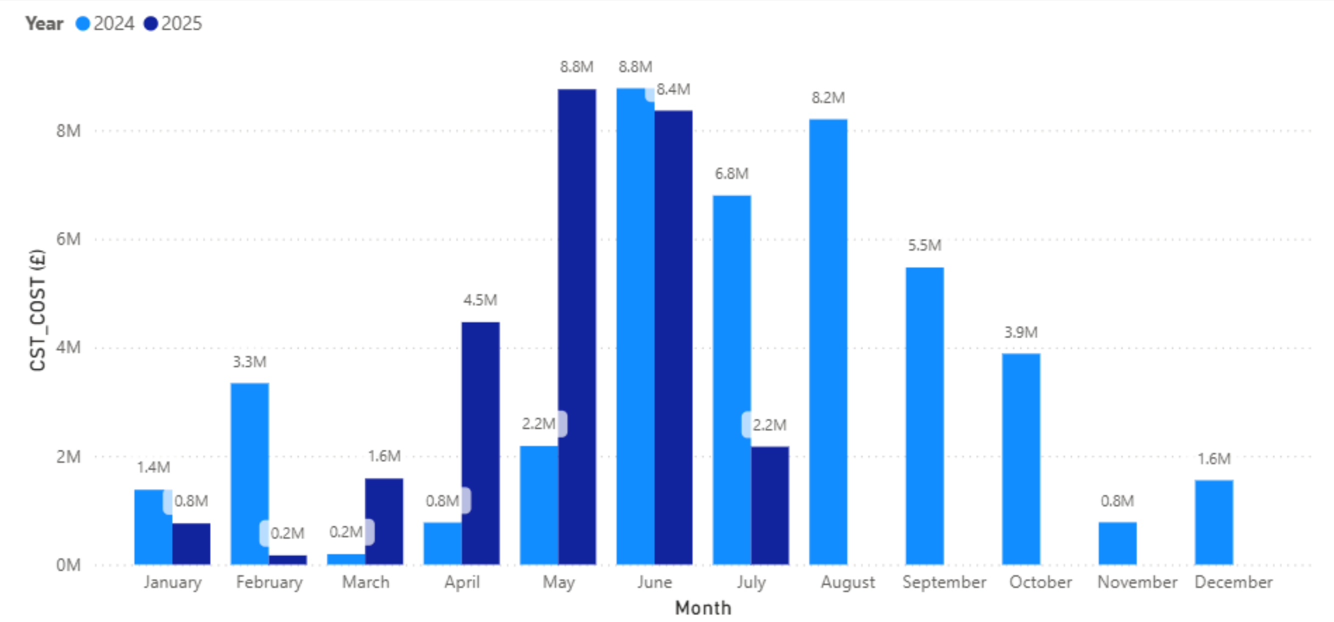
Thermal – Monthly system cost of actions for thermal management across 2024 and 2025:
Thermal constraints are associated with operational limitations on transmission assets due to temperature-related factors. In Great Britain, these are generally linked to highly congested areas in the Scottish region, 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 July, the system thermal constraint cost (which includes factors such as energy replacement and headroom) amounted to £92.8m, reflecting a reduction in costs compared to the previous month (£190.8m) but was up compared to the same period last year (£46.0m).



There was a large reduction in wind curtailment in July, from 1,159GWh in June to 428TWh in July. This followed a significant reduction in wind outturn month-on-month. Wind curtailment remained higher compared to July 2024. Ongoing planned outages in Scotland and Northern England are continuing to impact constraints, despite the lower wind outturn.

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. It is primarily provided by the rotating mass of large synchronous generators, mainly CCGTs in Great Britain, 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 July, the system inertia constraint cost (which includes factors such as energy replacement and headroom) amounted to £2.2m, which is a significant reduction compared to last month (£8.4m) and last year (£6.8m).



The expenditure on inertia dropped significantly in July. This was driven by a large reduction in wind outturn compared to the previous month and was also down slightly on July 2024. There was also a slight increase in demand over July 2024, particularly overnight. July consequently saw a larger number of synchronous units providing inertia regulation. This reduces the need for NESO to procure inertia through the Balancing Mechanism.

Reactive Costs/Volumes

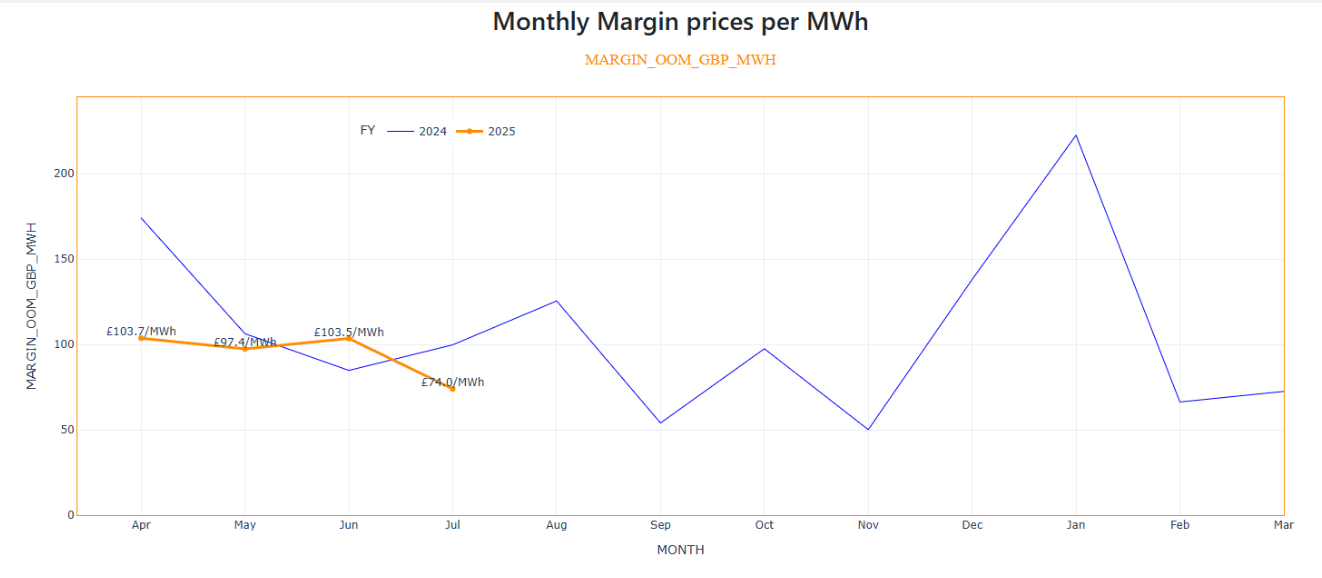
The volume-weighted average price for reactive power was £4.1/MVAr in July 2025.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
+£1.9m The volume-weighted average price increased to £4.1/MVAr up from £3.8/MVAr in June.	**-£0.6m** The volume-weighted average price increased from £3.8/MVAr to £4.1/MVAr compared to last year.

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

Reserve Costs/Volumes

Reserve prices decreased to £74.0/MWh in July from £103.5/MWh in June 2025. This decrease corresponds with a drop in the absolute volume of reserve actions taken in July by 73GWh compared to June.



Comparison Versus Previous Month	Comparison Versus Same Month Last Year
Operating Reserve: -£12.2m **Fast Reserve: +£1.2m** There was a 73 GWh decrease in the absolute volume of reserve required to secure the system compared to June.	**Operating Reserve: +£1.4m** **Fast Reserve: -£2.5m** There was a 51 GWh decrease in the absolute volume of reserve required to secure the system compared to July 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 see the benefit of more competitive and more liquid markets and the continued development of the Single Market Platform.

Comparison Versus Previous Month	Comparison Versus Same Month Last Year
-£3.2m There was a 30 GWh increase in the absolute volume of actions compared to June but clearing prices for most Dynamic Services were lower than the previous month.	**+£4.7m** The volume of actions taken for response increased 72 GWh compared to July 2024. Clearing prices were also higher year-on-year across all Dynamic Services.

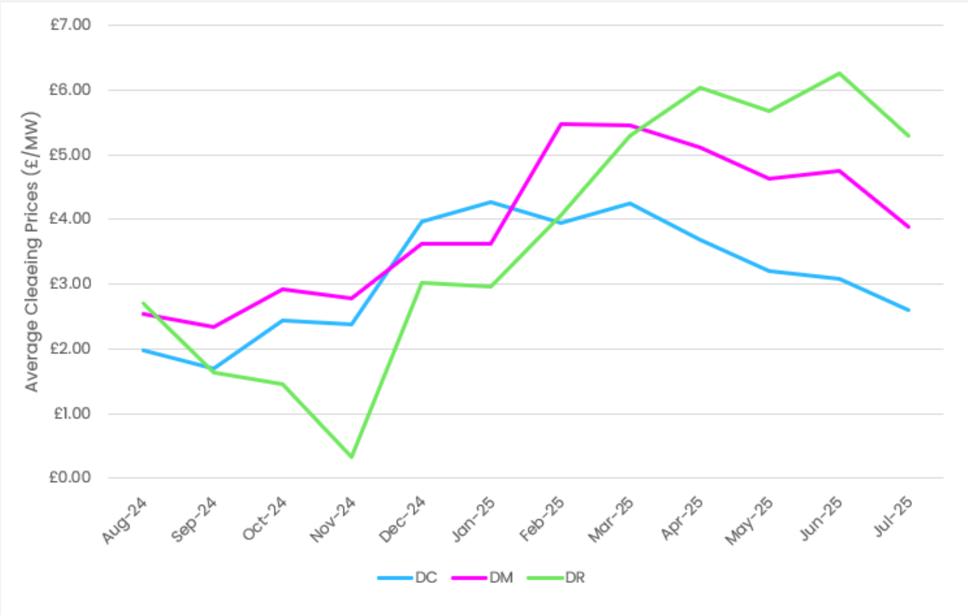
Dynamic Services Average Clearing Prices (£/MW): July 2025 vs June 2025

		(a) Jul-25	(b) Jun-25	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	2.6	3.1	(0.5)	
	DM	3.9	4.7	(0.9)	
	DR	5.3	6.3	(1.0)	

Dynamic Services Average Clearing Prices: July 2025 vs July 2024

		(a) Jul-25	(b) Jul-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Dynamic Services	DC	3.1	2.3	0.8	
	DM	4.7	2.7	2.1	
	DR	6.3	2.1	4.2	

Average clearing prices were down across all three of the dynamic services in July compared to the previous month. However, all three services saw an increase in average clearing prices to July last year, corresponding with the increase in wholesale price.

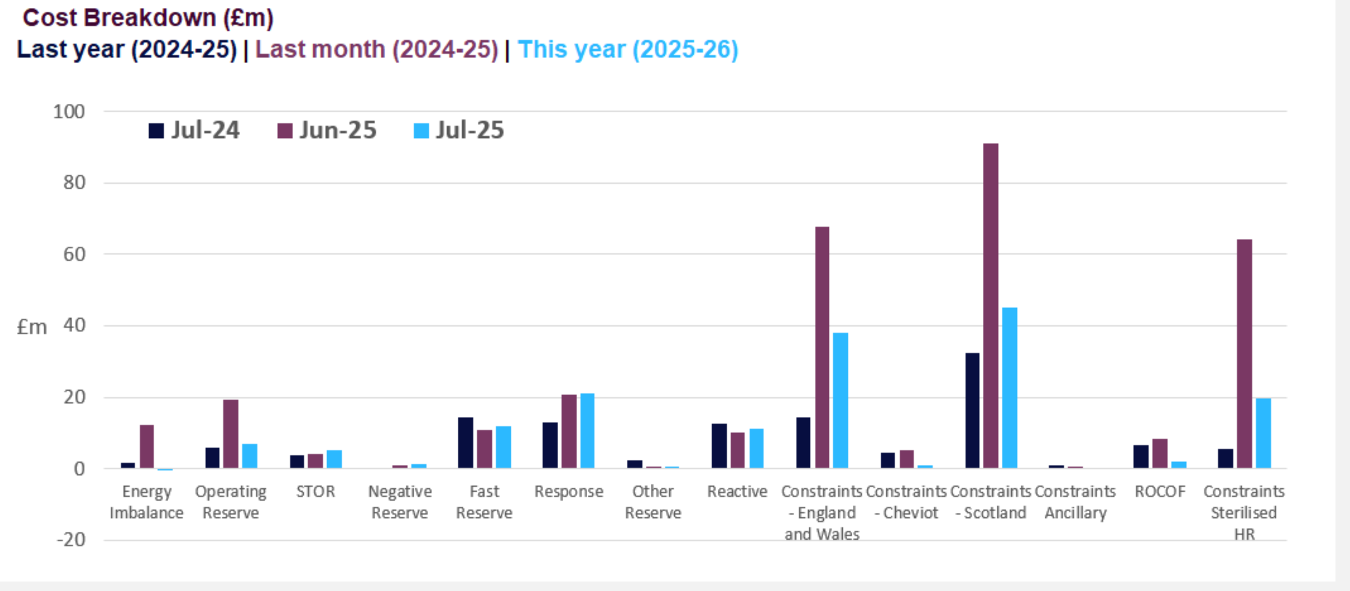


Comparison breakdown

Constraint costs reduced by £131.5m compared to the previous month. Lower costs were seen across all constraint categories, which is largely due to a significant reduction in wind outturn between the two months. Voltage and inertia spending also reduced month-on-month reflecting higher demand and an increased proportion of the generation mix met by synchronous generation. However, total constraint costs remained higher compared to last year despite a slight reduction in wind compared to July 2024. Ongoing outages in Scotland and Northern England have reduced constraint limits acting to push costs higher despite similar wind conditions.

Non-constraint costs fell by £27.6m compared to June 2025, with reductions in operating reserve and energy imbalance being the main contributors to this change.

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. The ongoing Review of Electricity Market Arrangements (REMA) is also considering options that could alleviate thermal constraints over the long term. 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 £85.1m in July 2025. This is broadly aligned with savings delivered in June 2025 (£81m). The most valuable action involved a new running arrangement at Pelham 400 kV substation, which significantly improved the transfer capacity of a constraint in the East Anglia by roughly 500 MW. The estimated cost savings for this action was roughly £18.9m.

Cost Savings – Trading

The Trading team were able to make a total saving of £13.0m in July through trading actions as opposed to alternative BM actions, representing a 27.5% increase on the previous month. Trading savings across July were down to substantial trading for both margin reasons and to help manage constraints in South-East England. In the South-East region there are limited BMUs in the area so where possible interconnector trades were priced against BM units, however in other cases they were taken with no alternative option. The greatest daily trading savings were £1.9m on 8 July with the greatest component being for downwards regulation. The day with the greatest spend on trades was 1 July at a cost of £5.9m with the greatest component being for margin.

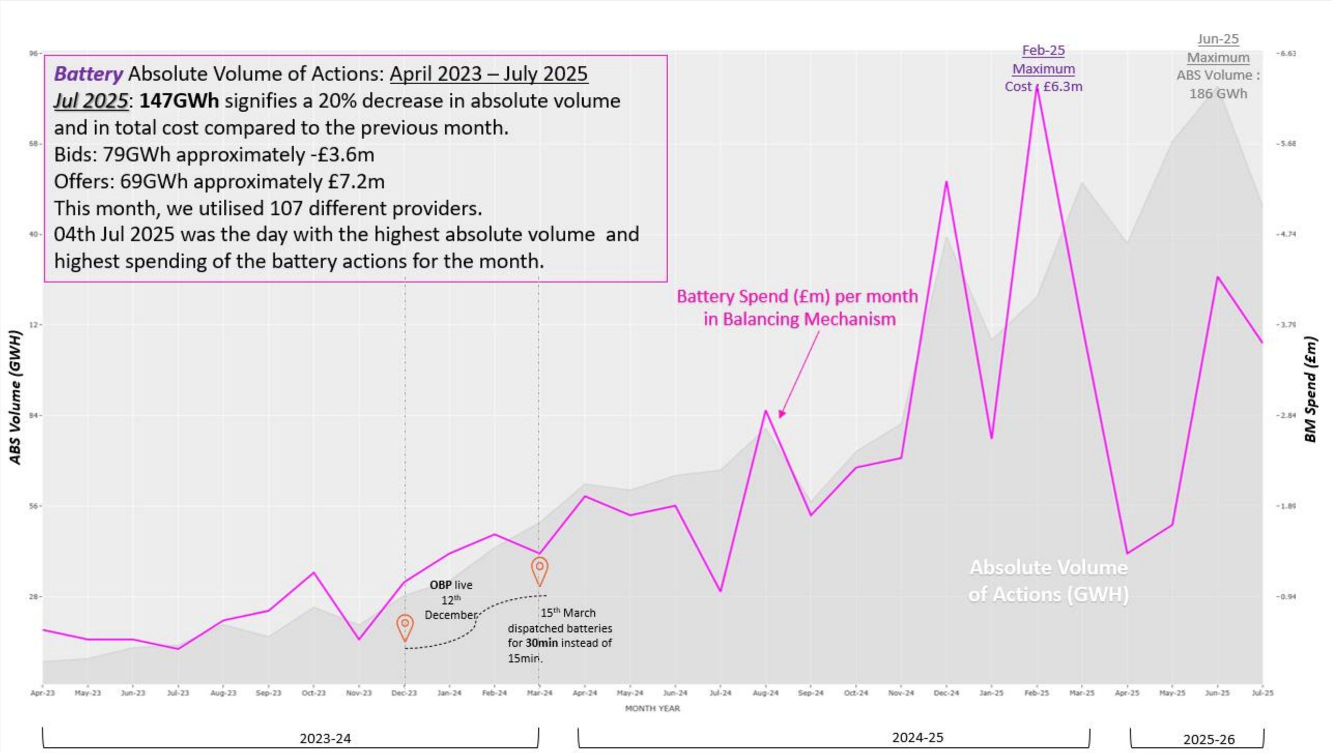
Cost Savings – Network Services (NS)

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 £40.3m in savings across 2025/26 to date (April – June 2025).

NOTABLE EVENTS

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

July 2025



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

In comparison to the previous month, June 2025, both the overall volume of actions and the total costs have decreased. 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 highlights our commitment to improving the flexibility of energy provision through battery storage and small Balancing Mechanism Units (BMUs).

DAILY CASE STUDIES

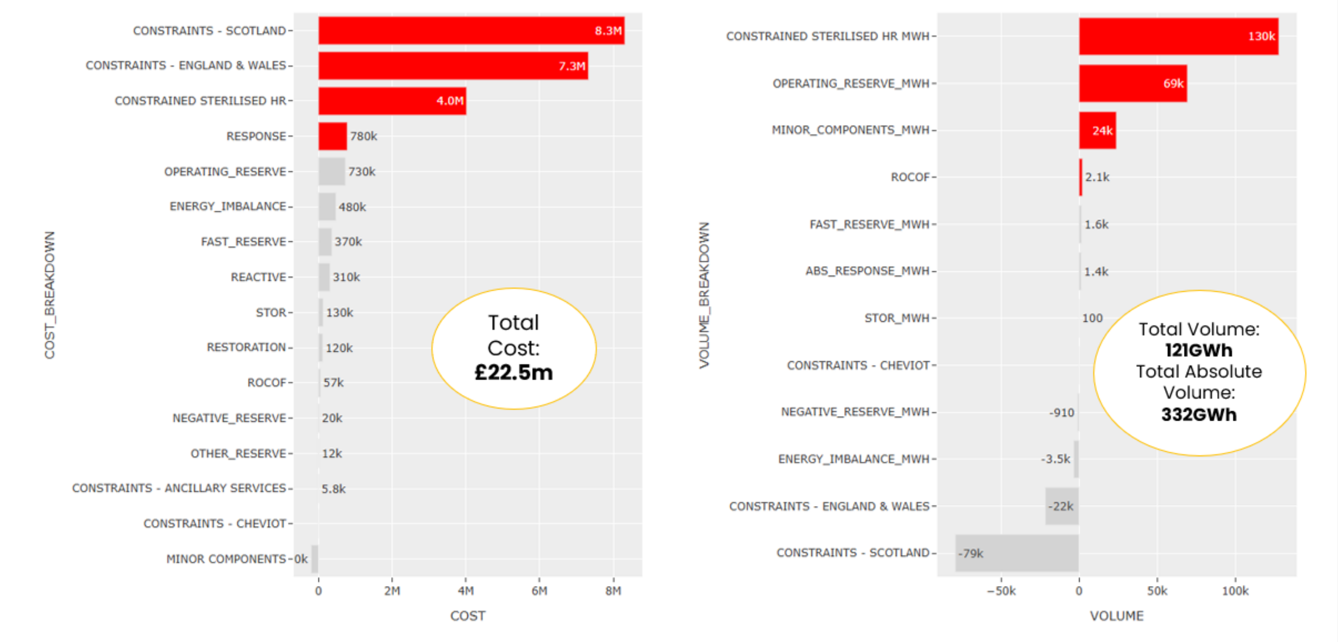
Daily Costs Trends

July's balancing costs were £167m which is £160m lower than the previous month. There was one day with a total cost above £15m (4 July). There were a further two days with costs above £10m which were 5 and 7 July. The daily average decreased by £5.3m from £10.8m in June to £5.5m in July.

The highest cost day on 4 July had a total cost of approximately £22.5m. The high costs corresponded with the high absolute volume of actions taken. High costs on this day were largely due to high spend on constraints, with the highest spend allocated to Scottish constraints. Units were also run on the day for voltage support and to support higher than expected demand.

The lowest cost day was 30 July at a cost of approximately £2.2m. The majority of the BM cost on the day was attributed to voltage management, and a low percentage of wind curtailment.

High-Cost Day – 4 July 2025



July 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.

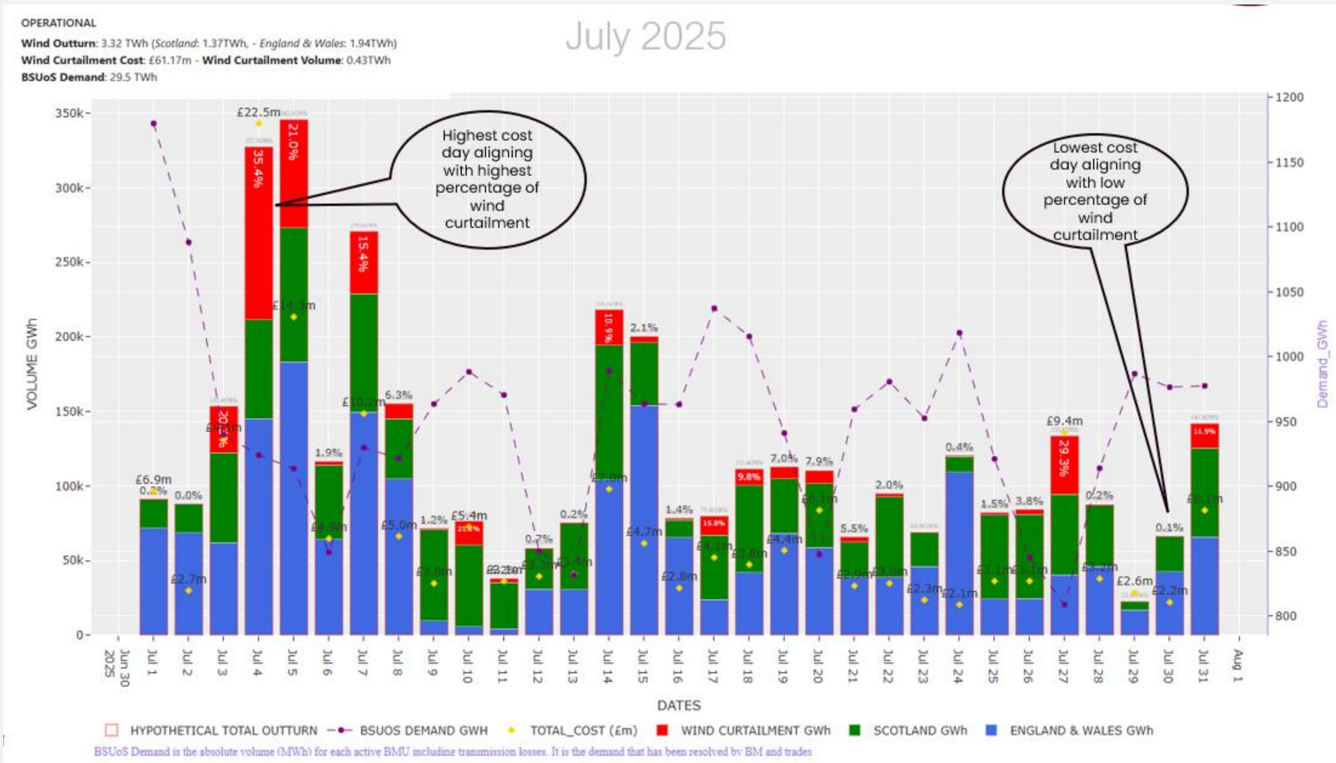
KEY: **Blue bars:** Wind generation in England and Wales

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).

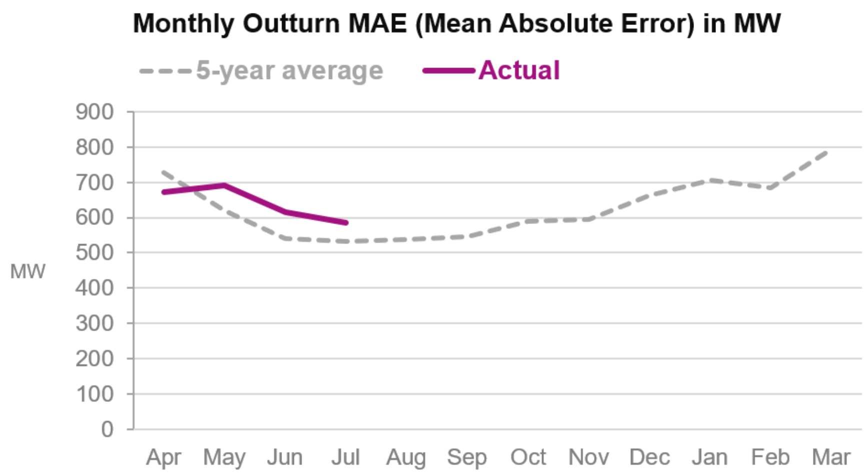
This Reported Metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each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

July 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**								

*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.

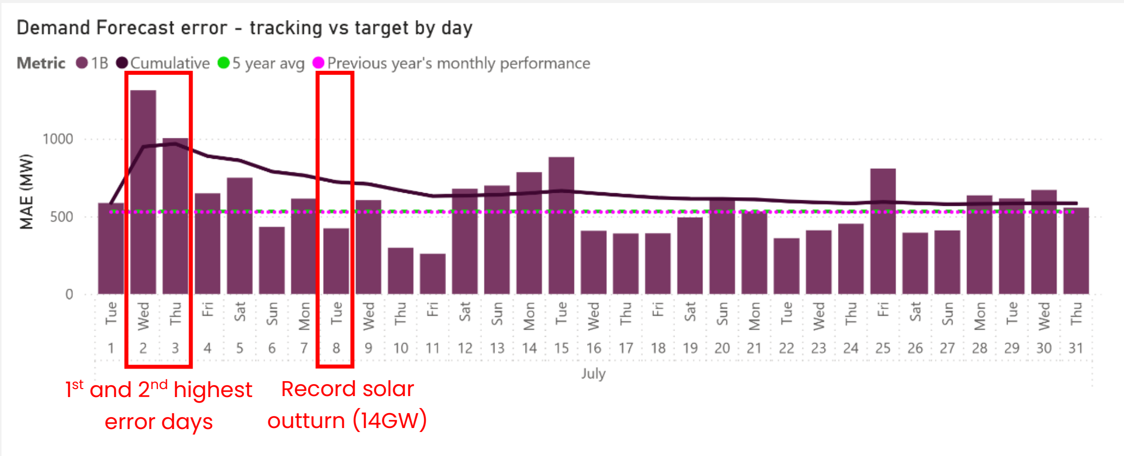
Supporting information

In July 2025, forecasting error averaged 584MW, presenting a 56MW (10.6%) increase on the previous 5-year average of 528MW.

July began with high temperatures and unsettled frontal weather systems bringing heavy rain and storms. This was followed by a temperature drop, before settling into higher-than-average temperatures, punctuated with occasional frontal systems.

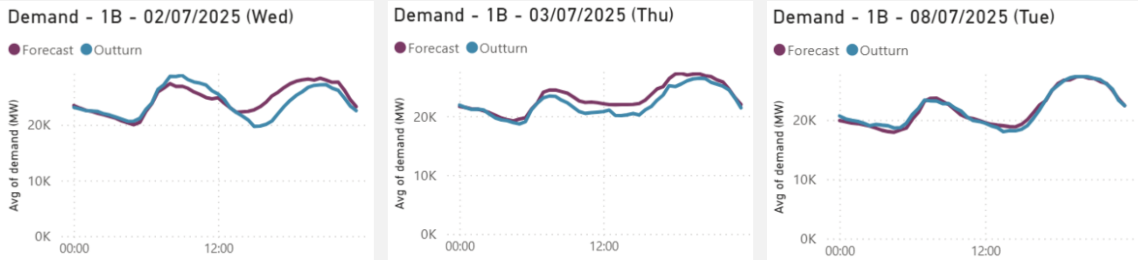
Solar forecasting errors remained the largest contributor to national demand errors and we aim to release a new National Solar model next month.

July also saw a new solar generation record set of 14GW, for the half hour ending 13:30 on 8 Jul.

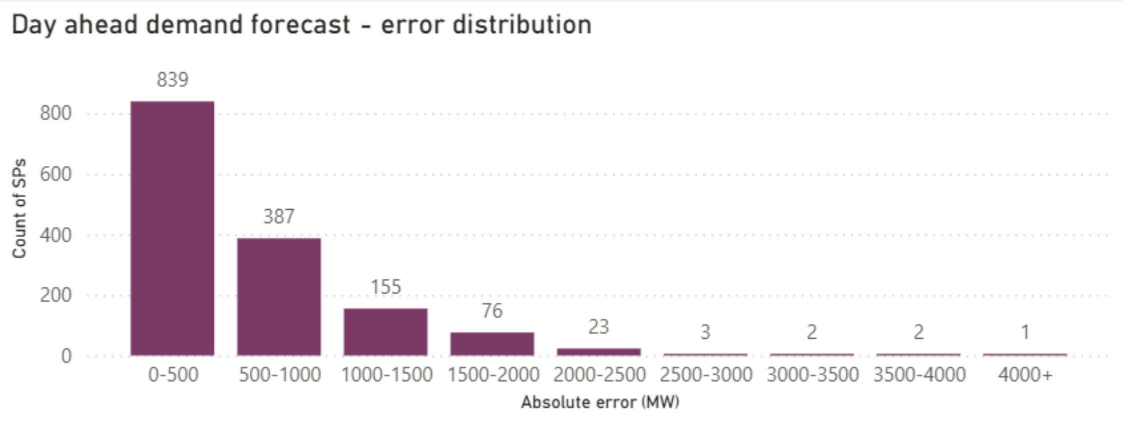


The largest absolute demand error this month was 4.5GW on 2 July, SP34.
The minimum demand was 15.6GW on 5 July, SP12

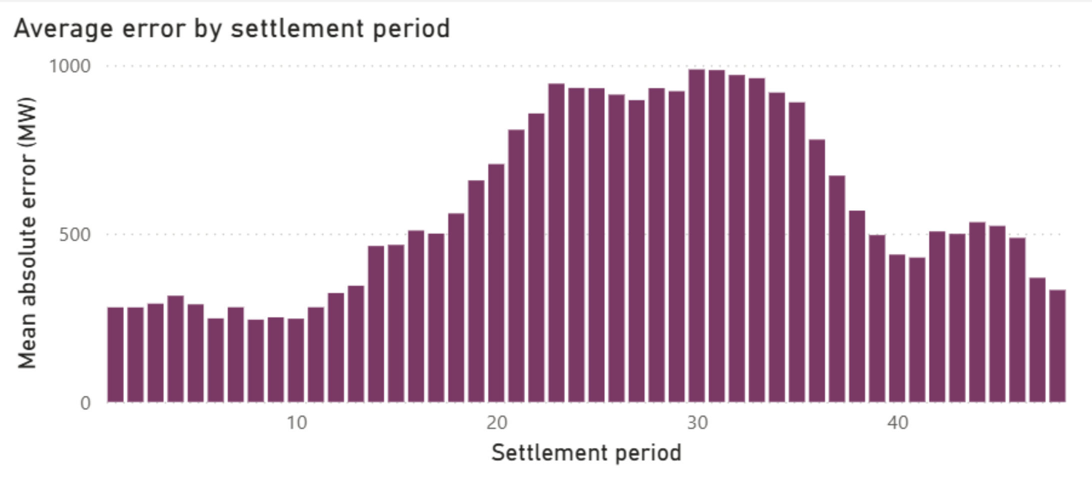
Days of Interest:



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 15 July.

Day	Error (MAE)	Major causal factors
2	1311	Solar forecasting errors, profiling errors and other factors not captured in models
3	1004	Solar forecasting errors
15	882	Solar forecasting errors

Missed / late publications

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

Demand Flexibility Service

Demand Flexibility Service (DFS) was used on 1, 4, 7-10, 16, 18, 21, 22, 24, 28, 29 and 31 July, with an accumulated total of 809MWh 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.

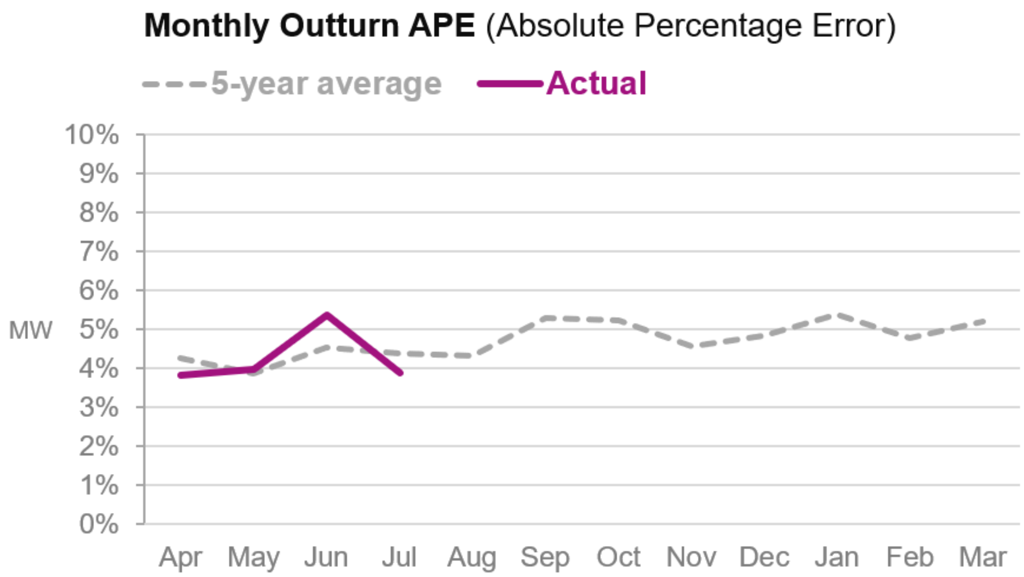
Sites deemed to have withdrawn availability are those that:

- 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.

July 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**	**3.87**								

*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 July 2025, BMU wind forecasting error averaged 3.87%, an improvement on the 5-year average of 4.39%.

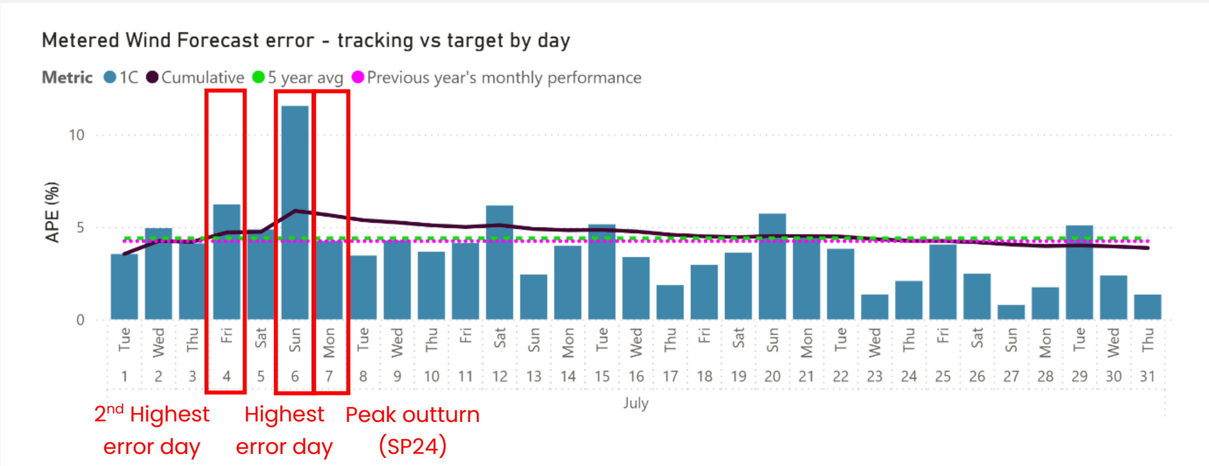
July was mostly dominated by high pressure weather systems, which generally keep wind levels lower and more stable. However, this high pressure system dissolved around 6 July, allowing frontal systems to pass over the UK, and resulting in a large Day-Ahead APE error of 11.9%. Our ithin-Day performance improved rapidly on this day and error was down to 2.1% at 6 hours ahead.

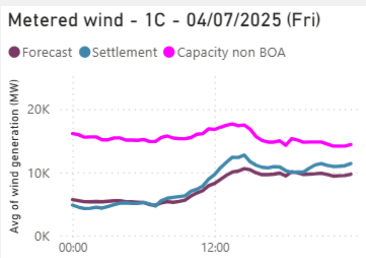
We experienced some front-end data processing issues in the first quarter, which resulted in the late processing of weather forecasts and a deterioration of the Day Ahead forecast performance. A fix was applied in the 2nd week of July and the performance returned back to expected levels.

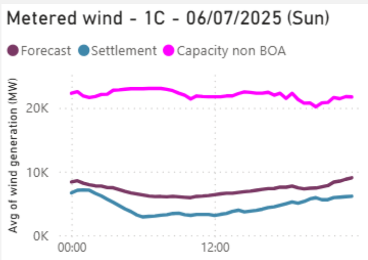
Wind generation peaked at 12.9GW on 7 July, SP19.
Wind forecast absolute error peaked at 4.2GW on 2 July, SP42.

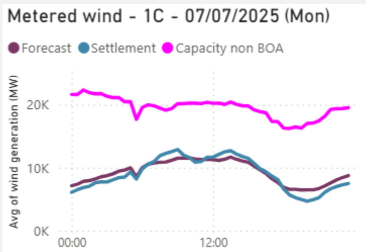
Note: metric performance for June has been recalculated with updated settlement data, which in this case has caused a slight decrease in reported accuracy.

Days of Interest:

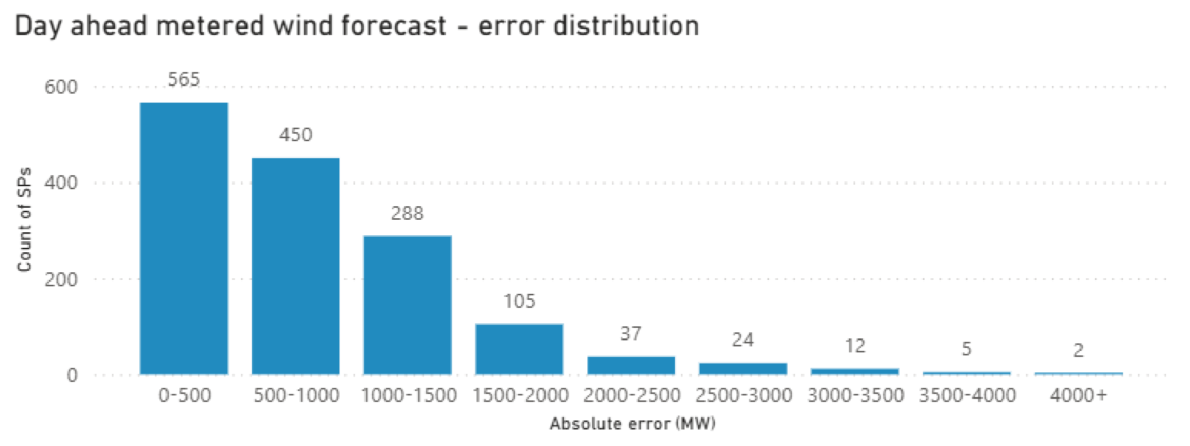








The distribution of settlement periods by error size is summarised below:



Details of largest error

Day	Error (APE)	Major causal factors
6	11.5	Wind speed forecast errors at day-ahead stage
4	6.22	Wind speed forecast errors at day-ahead stage

Missed / late publications

There were no occasions of missed or late publications in July.

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

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								
Offers – in merit Energy volume	148	205	356	215								
Offers – All in merit volume (System & Energy)	504	901	1052	529								
Bids – Skipped volume	150	154	118	130								
Bids – in merit Energy volume	336	352	234	277								
Bids – All in merit volume (System & Energy)	815	995	1576	962								
Combined Bid & Offer – skipped volume	213	225	234	208								

Supporting information

Q1 UPDATES

Reporting and methodology:

The definition of Post System Action (PSA) Skip Rate and the methodology to calculate skip rates were developed with LCP Delta and shared with industry in December 2024. We are currently reporting the PSA skip rate numbers for both bids and offers calculated at stage 5, which represents the actions available to our balancing team within the Control Room in real-time. The different stages within the methodology represent the removal of different types of units that are not accessible to balancing engineers in real-time. The stages are provided to aid transparency around units excluded from the final calculation rather than representing operational stages of the power system. Work is ongoing to add some of the identified limitations of the methodology into the calculation, which are dependent on the availability of data from the Open Balancing Programme (OBP) and currently planned for Q3 FY26.

Additional Metrics:

We have expanded this metric to include the skip rate by technology type, using two calculation methods. The first graph shows the Relative Technology skip rate for the current financial year, which shows how different technology types contribute to the overall skip rate. The second graph show the Technology Specific skip rate for each technology type for the last 3 months. This graph has been updated to include the skipped volume for each technology type as this metric can produce a very high skip rate when there is very low volume. The skipped volume on the Technology Specific graph is the total skipped volume for each technology type over the 3-month period shown. Both calculation methods are based on the PSA skip rate definition.

JULY UPDATES

Dashboard:

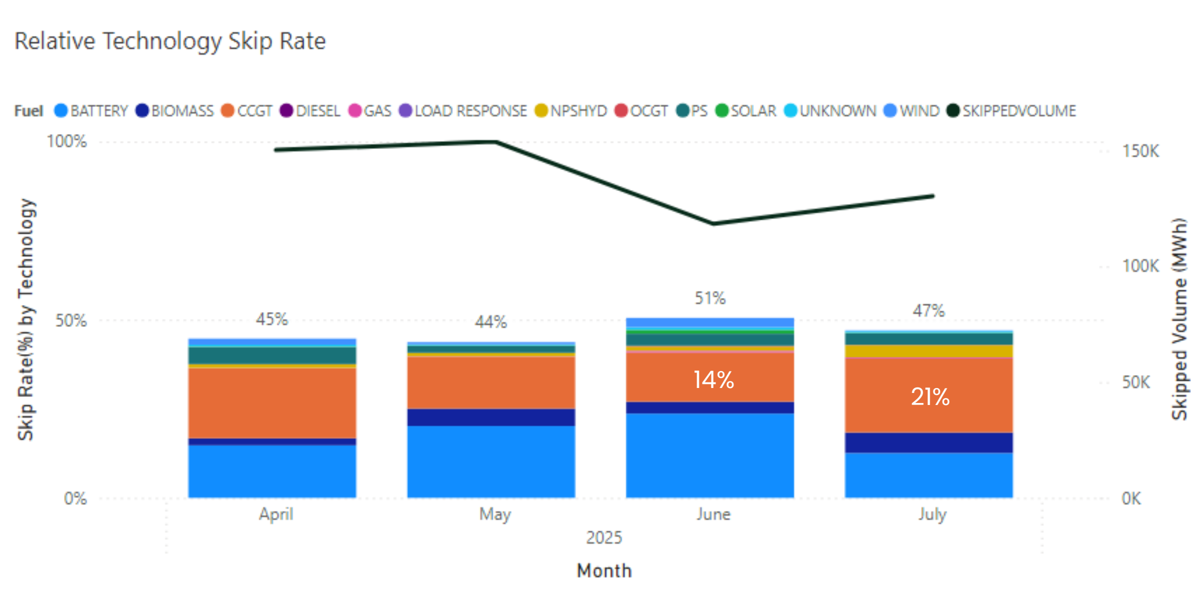
Following stakeholder feedback at the forum on 1 May and via the OTF, we have published an interactive dashboard on our skip rate webpage. This allows stakeholders to visualise skip rates and skipped volume at their chosen level of granularity. This includes viewing the data by Settlement Period, day, week or month, as well as filtering to show specific units or providers. We demonstrated this dashboard at our webinar on 7 August – slides and recording are available on our website.

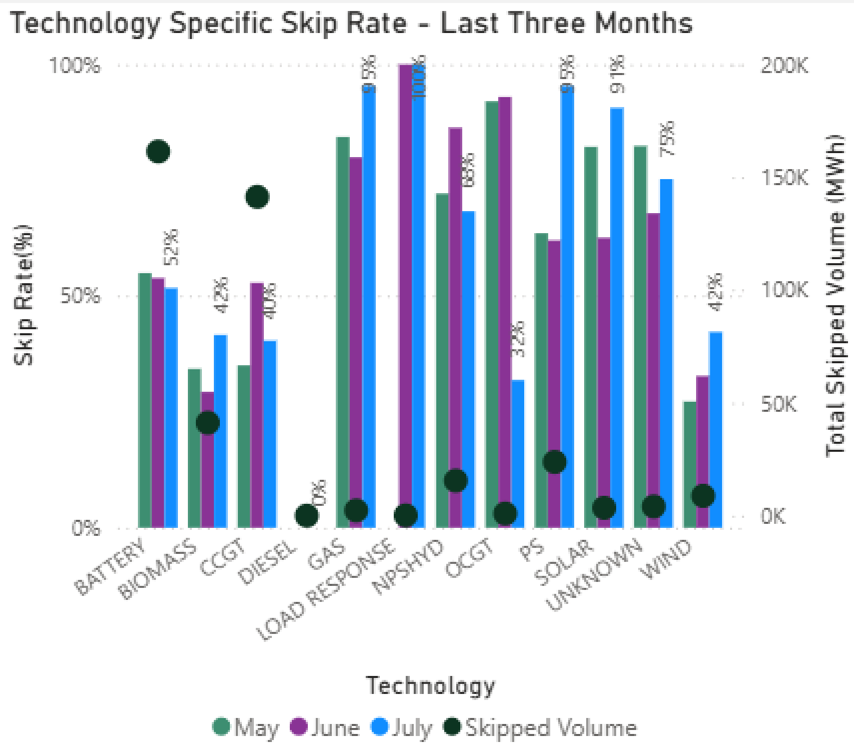
JULY PERFORMANCE

The Offer skip rate has increased from June (33%) to July (36%) but skipped volume has reduced due to a lower volume of actions taken in July. The Bid skip rate has decreased from 51% in June to 47% in July but the skipped volume has increased, as has the volume of bid energy volume. The combined bid and offer skip rate has increased from 40% in May and June to 42% in July.

Bids

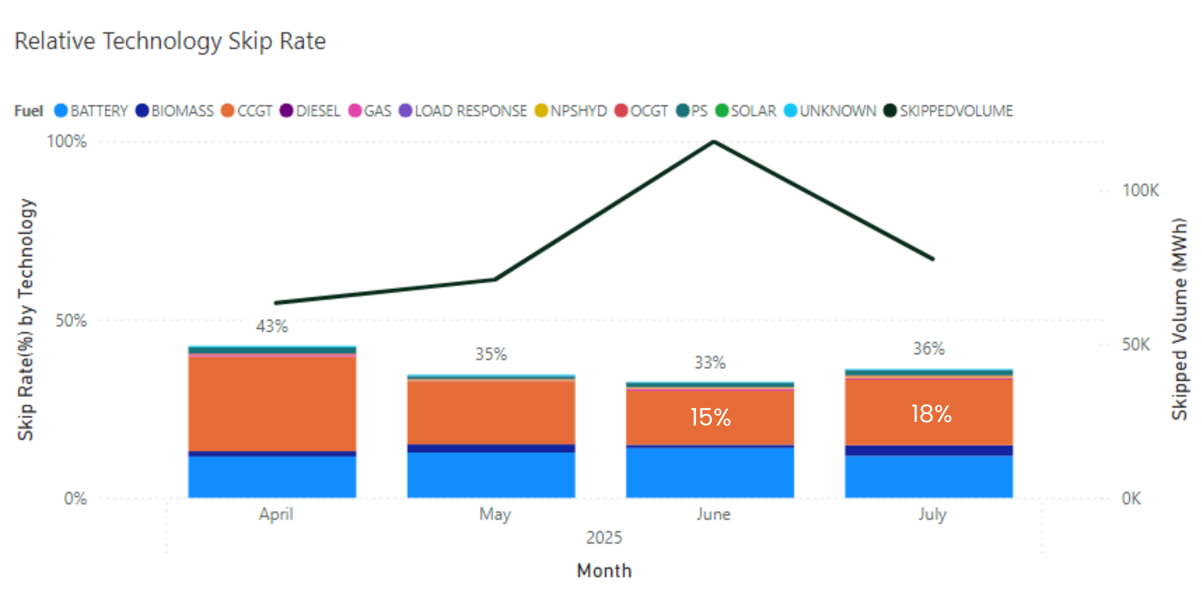
CCGTs accounted for a higher proportion of skipped volume in July compared to previous months – 21% in July compared to 14% in June. However, the Technology Specific skip rate for CCGTs has decreased from 53% in June to 40% in July. This shows that the increased proportion of CCGTs is due to more CCGT volume being in merit. The Technology Specific skip rate has remained fairly constant for batteries (52%-55%), but they account for a smaller proportion of skipped volume in July. This is due to less battery volume being in merit but a similar proportion being instructed.

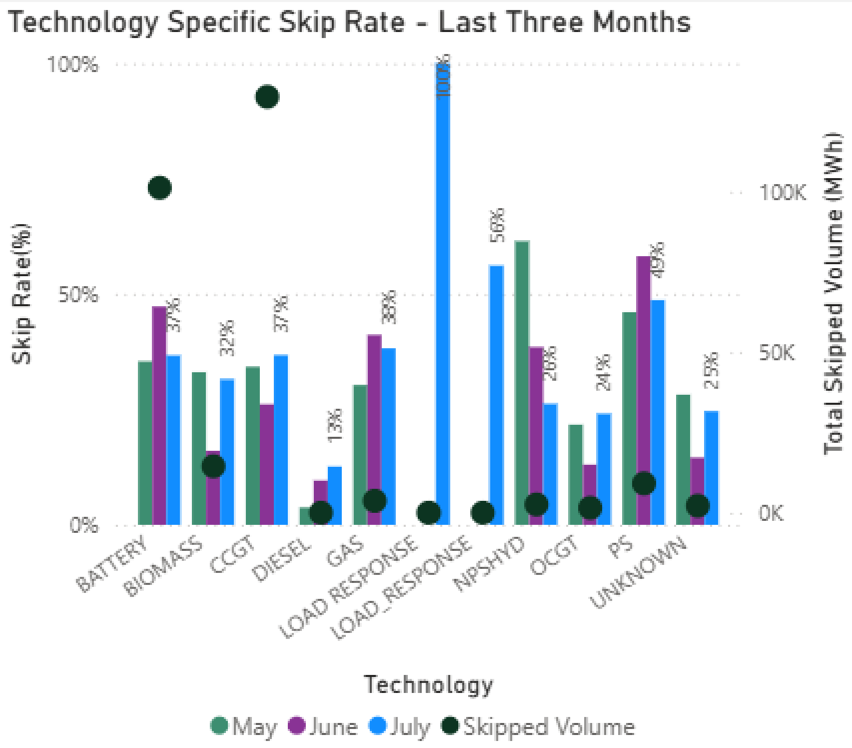




Offers

Similar to bids, CCGTs account for a higher proportion of skipped volume in July (18%) compared to June (15%). The Technology Specific skip rate has increased from 26% in June to 37% in July. This is due to additional response holding. Batteries account for a lower proportion of skipped volume and the Technology Specific skip rate has also reduced from 47% in June to 37% in July. This is due to lower in merit battery volume but a higher proportion of this volume being instructed.





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.

July 2025-26 performance

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

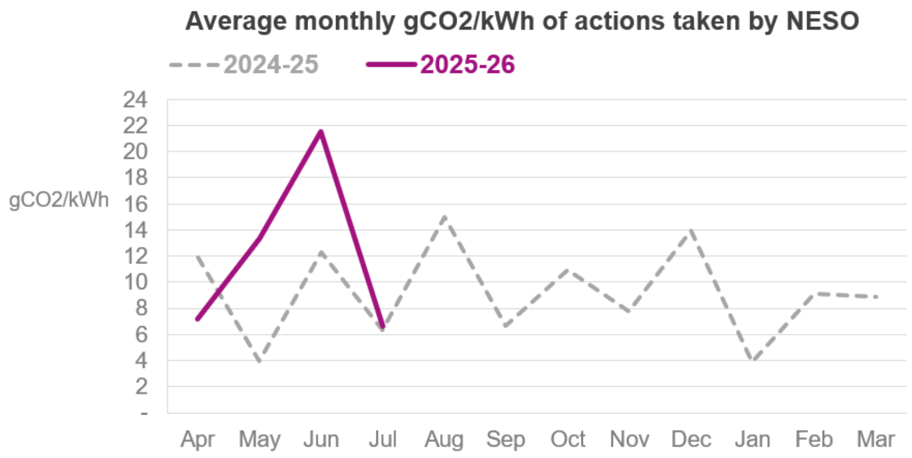


Table: Average monthly gCO2/kWh of actions taken by NESO

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

Supporting information

In July we continue to report the average monthly gCO2/kWh of actions taken by NESO in line with reporting requirements. Alignment of CP30 with ZCO technologies would see the inclusion of biomass, which has yet to be reflected in the figures reported.

In July, the average monthly carbon intensity from NESO actions was 6.64g/CO2/kWh. This is 14.89g/CO2/kWh lower than June and 5.5g/CO2/kWh less than the YTD average to 12.14g/CO2/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 76.32g/CO2/kWh which took place on 27July 2025 at 08:30. This is 6.38g/CO2/kWh lower than the highest point in June 2025 which took place on 12 June at 23.30.

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

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

Supporting information

There were no reportable frequency or voltage excursions.

[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.

July 2025-26 performance

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

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

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

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

Supporting information

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

This change took place on 10 July, 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 July.

There were no unplanned outages during July.

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